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STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota

FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION

This matter came on for hearing before Administrative Law Judge Kathleen D. Sheehy on April 20-27, 2006, at the Large Hearing Room of the Minnesota Public Utilities Commission (Commission), 350 Metro Square Building, 121 Seventh Place East, St. Paul, Minnesota.

Megan J. Hertzler and James Johnson, Assistant General Counsels, 414 Nicollet Mall, Fifth Floor, Minneapolis, MN 55401; and Richard J. Johnson, Esq., Michael J. Bradley, Esq., and Dan Lipschultz, Esq., Moss & Barnett, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, MN 55402, appeared on behalf of Xcel Energy (Xcel or the Company).

Linda S. Jensen and Julia E. Anderson, Assistant Attorneys General, 445 Minnesota Street, Suite 1400, St. Paul, MN 55101, appeared on behalf of the Department of Commerce (Department).

Ronald M. Giteck and Steve Alpert, Assistant Attorneys General, 445 Minnesota Street, Suite 900, St. Paul, MN 55101, appeared on behalf of the Office of Attorney General—Residential Utility Division (OAG/RUD).

Bryan Shirley, Esq., Kennedy & Graven, 470 U.S. Bank Plaza, 200 South Sixth Street, Minneapolis, MN 55402, appeared on behalf of the Suburban Rate Authority (SRA).

Robert S. Lee, Esq., and Andrew P. Moratzka, Esq., Mackall, Crounse & Moore, 1400 AT&T Tower, 901 Marquette Avenue, Minneapolis, MN 55402, appeared on behalf of Ford Motor Company, Gerdau AmeriSteel US, Inc., and Marathon Ashland Petroleum LLC (Large Industrials).

Scott G. Harris, Esq., Leonard, Street and Deinard, 150 South Fifth Street, Suite 2300, Minneapolis, MN 55402, appeared on behalf of Excelsior Energy, Inc.

Alan R. Jenkins, Esq., McKenna Long & Aldridge, 303 Peachtree St. NE, Suite 5300, Atlanta, GA 30308, appeared for a consortium of commercial customers of Xcel (the Commercial Group).[1]

Bradley Hendrikson, Esq., and Richard J. Savelkoul, Esq., Felhaber, Larson, Fenlon & Vogt, 444 Cedar Street, Suite 2100, St. Paul, MN 55101, appeared on behalf of the Minnesota Chamber of Commerce.

Pam Marshall, Esq., and Chris Duffrin, Assistant Director, Energy CENTS Coalition (ECC), 823 East Seventh Street, St. Paul, MN 55106, appeared on behalf of ECC.

Myer Shark, Esq., Suite 221, 3630 Phillips Parkway, St. Louis Park, MN 55426, appeared for himself.

Susan Mackenzie, Marc Fournier, Louis Sickmann, and Clark Kaml appeared for the staff of the Commission.

STATEMENT OF THE ISSUES

During the course of this proceeding many issues have been resolved either through changes in position set forth in testimony or through various settlements, which will be described below. The following disputed issues remain:

Financial Issues

- Should rates be adjusted effective January 1, 2007, because Flint Hills is expected to return as a full-requirements customer as of that date?
- What is the appropriate level of post-retirement medical benefits to include in rates?
- Should a severe storm reserve be established, or alternatively, should expenses for tree trimming be increased?
- What amount of incentive compensation should be allowed in rates?
- Should a 6- or 10-year amortization period be used for recovering the investment in a private independent spent fuel storage installation?
- Should Xcel be allowed to recover its deferred expenses related to the Time-of-Use pilot program?

Cost of Capital

What is the appropriate ROE?

What is the appropriate ROR (based on the ROE)?

Income Taxes

- Is Xcel's income tax expense appropriate?

Rate Design

- Is the proposed embedded Class Cost of Service Study reasonable?
- How should the revenue requirement be allocated to the customer classes?
- How should the Fuel Clause Rider mechanism be adjusted?
- Are Xcel's Dual Feeder Service rates reasonable?
- Are Xcel's proposed interruptible riders reasonable?
- How should the fuel clause credit be determined for the WindsSource rate?
- How should the amount of contribution in aid of construction (CIAC) be determined?
- Should Xcel be allowed to determine the form of payment for CIACs?

Miscellaneous

- Should the proposed Financial Neutrality Factor be approved?

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

Procedural Background

1. Xcel Energy Inc. (XEI), a Minnesota corporation, is a public utility holding company. XEI has four utility subsidiaries that serve electric and natural gas customers in ten states, as well as several non-utility subsidiaries. The utility subsidiaries are Northern States Power Co., d/b/a Xcel Energy (NSP-MN), a Minnesota corporation; Northern States Power Co. (NSP-Wisconsin), a

Wisconsin corporation; Public Service Company of Colorado; and Southwestern Public Service Co. These utilities serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin.

2. On November 2, 2005, Xcel Energy filed an application for a proposed rate increase of $168,047,000 (or 8.05% of total revenues). Xcel used a projected 2006 calendar year as its test year for this proceeding.

3. Several parties, including Myer Shark, challenged Xcel's petition as premature, given the terms and provisions in Xcel's merger stipulation agreements and in the Commission's *Order Approving Merger, As Conditioned* (Merger Order), issued June 12, 2000, in Docket No. EG-002/PA-99-1031.

4. On December 27, 2005, Myer Shark filed a petition for reconsideration and a request to stay the interim rates approved by the Commission at its meeting on December 15, 2005.

5. On December 29, 2005, Xcel filed an objection to the request for a stay.

6. On December 30, 2005, the Commission found Xcel's application to be substantially complete.[2] On the same date, the Commission issued an order authorizing Xcel to collect, on an interim basis, an annual revenue requirement of $2,229,876,000, which includes an interim rate increase of $147,318,000 (approximately 7.06%) effective January 1, 2006.[3]

7. On January 30, 2006, Rebecca S. Winegarden and Myer Shark filed petitions asking for reconsideration of the Commission's *Order Accepting Filing and Suspending Rates*.

8. Pursuant to the First Prehearing Order, the petitions for intervention of the following persons were granted: Large Industrials; Legal Services Advocacy Project; ECC; International Brotherhood of Electrical Workers, Local Union 23 (IBEW Local 23); International Brotherhood of Electrical Workers, Local Union 949 (IBEW Local 949); the Minnesota Chamber of Commerce; the SRA; Excelsior Energy; and Myer Shark and Rebecca Winegarden.[4]

9. Pursuant to the Second Prehearing Order, the intervention petitions of the following persons were granted: Minnesota Power; the Commercial Group; Otter Tail Corporation, d/b/a Otter Tail Power Company; the Board of Water Commissioners of the City of St. Paul; International Paper Corporation; and the Metropolitan Counties Energy Task Force. After their petitions to intervene were granted, the following persons withdrew as parties: IBEW Local Union Nos. 23 and 949 and Rebecca Winegarden.[5]

10. On March 13, 2006, the Commission denied the Motion for Reconsideration and Request to Stay Interim Rates.

11. Public hearings were held on several dates from March 3, 2006 through April 20, 2006, to receive comments and questions from non-intervening ratepayers. The hearings took place at the Minneapolis Community and Technical College in Minneapolis; the St. Clair Recreation Center in St. Paul; the Prom Center in Oakdale; Winona City Hall, Winona; the Intergovernmental Center in Mankato; the Stearns County Courthouse in St. Cloud; by videoconference in Moorhead and Maple Grove; the Chippewa County Government Center in Montevideo; and at the Commission offices in St. Paul. A total of 111 members of the public participated in the public hearings.

12. Members of the public raised a number of issues in the public hearings; in addition, the Administrative Law Judge received written public comment addressing the same basic issues.[6] The issues of concern to the public were: total energy expense, and the impact of increased energy bills on fixed- and low-income residential consumers; how much of the revenue requirement would be allocated to the residential class; the amount of the fixed monthly charge; a desire to encourage the use of more renewable resources to generate energy; a desire to encourage the use of resources less expensive than gas, such as coal and nuclear facilities, to generate energy; a desire to ensure that executive compensation is not excessive; questions concerning Xcel's income tax expense in light of NRG's financial difficulties; and the desire of shareholders that rates be set to permit a fair rate return on their investment. In southwestern Minnesota, several members of the public also raised service quality issues.

I. RATE BASE

A. Working Capital – Billing Component of Lead/Lag Study

13. Xcel calculates its cash working capital requirement by applying lead/lag study factors to its test-year operating and maintenance (O&M) expenses to determine its cash working capital requirement. Xcel's initial cash working capital proposal in this case was based, in part, on use of a 2.9-day interval between the meter-read date and the billing date.[7] Updated data showed that the actual interval under Xcel's new billing system is 1.8 days. Based on this updated information, the Department proposed a corresponding adjustment that reduces the revenue lag of 46.78 days to 45.68.[8] Xcel accepted the Department's adjustment, which reduces the working capital requirement. Xcel further reduced its working capital by including a lag-time adjustment (from 41.61 days to 39.63 days) for transmission-related revenues.[9] No party opposes the proposed cash working capital requirement with these adjustments.

14. The numerical impact of this change depends on whether the Commission accepts the Department's proposal to adjust rates effective January 1, 2007, because of the return of Flint Hills as a full-requirements customer on that date (see below).

II. OPERATING INCOME

A. Return of Flint Hills as Full Requirements Customer

15. Koch Refining Company, L.P. (now known as Flint Hills Resources) was Xcel's largest retail customer in the last rate case, MPUC Docket No. E002/GR-92-1185. This means that rates set then reflected Xcel's cost of capacity needed to generate, transmit and distribute electricity for Flint Hills, as well as the revenues expected to be received from Flint Hills Resources.

16. In 1996 Flint Hills sought legislation that would allow it to build a cogeneration facility to serve its load and be exempted from personal property taxes otherwise applicable to generation assets. If Flint Hills had constructed the proposed facility, Xcel would have faced the loss of Flint Hills' generation and transmission revenues. The resulting legislation, Minn. Stat. § 216B.1621, authorizes a customer that proposes to build or acquire its own generation to negotiate a discount in exchange for delaying construction of the generation. Xcel and Flint Hills reached an agreement to defer the proposed facility, but the efforts to negotiate a discount were not successful; instead, Flint Hills arranged for its own electricity to be supplied from a coalition of cooperatives. Eventually, Flint Hills and Xcel reached an agreement under which Xcel would deliver the power from the third-party supplier to Flint Hills, for which Flint Hills would pay a transmission and distribution rate. Xcel subsequently filed for approval of a tariff to provide the transmission and distribution services contemplated under the agreement. The Commission approved the proposal as a contract service (as opposed to a general tariff) on September 29, 1998.[10] The contract to provide distribution and transmission services to Flint Hills expires December 31, 2006.[11]

17. In approving the agreement in 1997, the Commission reserved for future consideration the issue whether Xcel could recover any resulting revenue shortfall, due to the departure of Flint Hills, from other ratepayers.[12]

18. In this rate case, Xcel did not explicitly seek to recover any lost revenues associated with the Flint Hills agreement.[13]

19. The Department accepted Xcel's forecasted capacity and energy needs for the 2006 test year, with the exception of questioning whether the 1996 Flint Hills contract created stranded generation capacity that required an adjustment. In its initial testimony, the Department advocated decreasing Xcel's test year revenue requirement by $19,524,997, unless Xcel made an affirmative showing that the Flint Hills contract was either beneficial or neutral to other ratepayers.[14]

20. In rebuttal testimony, Xcel disclosed that Flint Hills had informed Xcel in February 2006 that it would return as a full requirements customer when its contract expires December 31, 2006. When that happens, on January 1,

2007, Flint Hills will return to its status as Xcel's largest customer. Flint Hills is expected to account for about 3% of Xcel's retail energy sales in Minnesota.[15]

21. The Department now agrees that no adjustment to the 2006 test year period is appropriate with respect to the return of Flint Hills; it advocates, however, that rates effective January 1, 2007, forward should be adjusted to reflect a known and measurable change of approximately $19 million in anticipated revenues from Flint Hills. This number represents the difference between the incremental revenues and average cost of fuel and purchased energy.[16]

22. Xcel maintains for a variety of reasons that this adjustment should not be made. Xcel argues first that this change would be outside the test year, and that Commission policy would not permit accounting for a known and measurable change outside the test year absent compelling reasons, which it contends are not present in this case.

23. Xcel also argues that, if such an adjustment to revenues were made, then other costs of providing service to Flint Hills should be offset. The Department's figure of $19 million was calculated based on the assumption that Flint Hills would take service under the A14 rate. Xcel maintains that, at the A14 rate, after additional incremental capacity costs are considered and are allocated based on jurisdictional shares, and after total production costs are adjusted and revenues from the current service agreement are subtracted, the net adjustment is $17,507,920.[17]

24. Xcel also contends that when Flint Hills returns as a full requirements customer, it will take service at the A15 rate. When the A15 rate is used to calculate retail revenues, the net adjustment contemplated by the Department, after inclusion of the other costs identified by Xcel above, is $16,637,966.[18]

25. The Department maintains that no incremental capacity costs should be offset because capacity costs sufficient to serve Flint Hills in 2007 are already built into the 2006 test year. This argument is based on the fact that in Xcel's 2004 Integrated Resource Plan (IRP), Xcel said it would need 750 MW of short-term capacity to cover peak summer needs in 2006.[19] For purposes of the rate case, and based on a 2006 demand forecast, Xcel assumed 903 MW of short-term capacity would be needed for 2006.[20] The Department argues that the difference between these numbers (153 MW) demonstrates that Xcel has built sufficient short-term capacity into the test year to serve Flint Hills (which requires about 144 MW).

26. Xcel has demonstrated that its estimate of short-term capacity needs for the test year does not include the short-term capacity costs of serving Flint Hills in 2007. Xcel has pointed out that, beginning in 1999, it began adding additional capacity of 100 to 150 MW to meet annual growth in peak demand.[21]

Between 1998 and 2004, the growth in energy consumption was approximately 1.5% per year, or approximately 9% over this period.[22] Any excess capacity from the loss of Flint Hills in 1999 was quickly consumed by other growth in demand. Furthermore, Xcel has shown that it does not make year-to-year short-term capacity purchase decisions based on the 2004 Resource Plan, but rather makes such decisions based on independent studies of peak demand, which assumed Flint Hills would remain a contract service customer for 2006.[23] As a consequence, there is no "excess" capacity in the 2006 test year, and any adjustment to revenues to reflect the return of Flint Hills in 2007 should also take into account the short-term capacity cost of serving Flint Hills during the peak summer months of 2007.

27. There are compelling reasons to account for the return of Flint Hills as a full requirements customer as of January 1, 2007. This is a known and measurable change that will take place less than a millisecond outside of the test year. Xcel selected the test year and controlled the timing of the filing of the rate case. If this change is not accounted for now, rates going forward will fail to reflect significant annual revenues from Xcel's largest customer, although its energy costs will be distributed through the fuel adjustment clause. Under these unique circumstances, a net adjustment of $16,637,966 to decrease Xcel's revenue requirement for the period January 1, 2007, forward is appropriate and necessary. This is the number calculated by Xcel to reflect service at the A15 rate with the additional capacity costs for the summer of 2007.

28. Xcel also argues that if the Commission includes the Flint Hills margins for 2007 going forward, it must offset all other known and measurable costs that will increase in 2007, whether or not these costs are related to Flint Hills. Xcel has identified four other cost increases that it contends should be reflected in any stepped rate adjustment beginning January 1, 2007. They are: Increased selective catalytic reduction (SCR) operating costs at the A.S. King plant, the Minnesota jurisdictional share of which is $2,707,000; Nuclear Regulatory Commission (NRC) fees of $1,387,000; Nuclear Management Company (NMC) costs of $5,202,000; and bad debt expense of about $3,441,000.

29. While any costs related to Flint Hills should be accounted for in the adjustment, the Administrative Law Judge does not recommend inclusion of these unrelated costs in rates effective January 1, 2007. Neither the timing nor the amount of these expected increases is nearly as certain as the timing and amount of the Flint Hills margins. The SCR operating costs are budgeted for May through December 2007; the amount of the NRC and NMC costs is not certain, nor is the timing clear; and the estimated bad debt expense is simply a trend at this point that is expected to continue. Whereas the inclusion of the Flint Hills margins would correct a substantial mismatch between revenues and costs going forward, inclusion of these unrelated costs would be inconsistent with the test-year concept.

B. FAS 106 Historical Costs

30. The only disputed issue related to FAS 106, post-retirement medical costs, is whether rates should be based on the actuarially established 2006 costs ($8,967,000), or whether, as the Department recommends, rates should be based on a five-year average of the historical costs between 2000 and 2004 ($7,702,000).

31. The 2006 test year FAS 106 expense was determined by Xcel's independent actuaries, Watson Wyatt Worldwide. The Department does not dispute the accuracy or reasonableness of the claimed 2006 expense.[24] Instead, the Department questions whether the 2006 expense is atypical and therefore not a reasonable basis upon which to set rates.

32. Xcel's actual FAS 106 expenses (on a Minnesota jurisdictional basis) for the past six years, along with the projected expense for 2006, are as follows:

2000: $6,261,000

2001: $6,423,000

2002: $7,158,000

2003: $9,010,000

2004: $8,123,000

2005: $8,886,000

2006: $8,967,000 (projected test year)[25]

33. The FAS 106 expense has increased over the last six years primarily due to increasing medical costs. The sole decrease, from 2003 to 2004, was primarily due to the effect of the Medicare Prescription Drug Improvement and Modernization Act signed into law in December 2003.[26]

34. Over the last five years (2001 through 2005) the actual per capita claims cost has significantly exceeded the expected increase assumed in the FAS 106 actuarial calculation for each year, making the actuarially determined 2006 test year expense conservative compared to actual claims experience. This trend of increases in actual claims experience will lead to higher levels of post-retirement medical expense in the future, not lower levels.

35. The Department used a five-year average of 2000 to 2004 actual costs in determining the level of costs to recover in rates.[27] The resulting average cost ($7,702,000) is lower than the actual costs in any year since 2002.

36. The Department argues that using a lower expense is justified based on the fact that post-retirement medical benefit costs will eventually begin to shrink, because Xcel no longer offers these benefits to its employees.[28] The Department provided no cost analysis, however, to support its position that the pool's eventual shrinkage justifies setting the expense at this level.[29]

37. Xcel provided actuarial evidence that shrinkage of the pool will not result in a decrease of expense to the level proposed by the Department until the year 2013, assuming no change in inflationary assumptions.[30]

38. The Department states that its use of a five-year historical cost average is consistent with the manner in which FAS 106 costs were determined in the Interstate Power and Light (IPL) rate case and further notes that the Department proposed a similar process for setting rates in the recent Xcel Energy Natural Gas rate case.

39. In the IPL 2003 Rate Case, IPL used a 2002 historical test year. IPL proposed a known and measurable increase of $460,798 for the projected 2003 year; however, the actuarially established expense for 2004 was also known and measurable and it was $104,000 less than the 2003 expense. On that basis, the Department proposed, and the Commission agreed, that IPL's costs should be based on the 2004 amount increased by one-fifth of the 2003 increase. That is, the amount of the 2003 known and measurable increase was "levelized" to make a reasonable upward adjustment from the 2002 historic test-year level.[31] IPL's rates were based on historic test year expenses with an upward adjustment; IPL was not denied recovery of its test year costs, as would occur under the Department's proposal in this proceeding.

40. In Xcel's 2004 Natural Gas rate case, while the Department recommended a similar adjustment and Xcel accepted it, it was part of a settlement without precedential value.[32]

41. Xcel's estimated cost for 2006 post-retirement medical costs--$8,967,000—is reasonable and should be used to determine rates.

C. Severe Storm Reserve/Tree Trimming Expense

42. In 1998 and 1999, Xcel's system had significant storm-related outages related to insufficient tree trimming. In 1998, in response to customer complaints and Commission inquiries, Xcel committed to spend an additional $3 million on its tree-trimming program, with total expenditures of about $18 million for 1999. In 1999, at the conclusion of a service quality investigation, Xcel agreed to improve system reliability with increased tree trimming and cable replacements; it committed to spend from $15 to $20 million over amounts that were then reflected in rates for these activities by January 1, 2005.[33]

43. Xcel initially proposed a $2 million increase in test year expenses to establish a severe storm reserve. Xcel has not explicitly budgeted for severe

storms in the past and has attempted to manage the costs of storms within its existing O&M budget. Xcel proposed that in the event that there is incremental O&M for severe storms in Year 1, it would, over the course of 12 months, record an expense equal to $2 million and credit a liability account, in much the same way as a provision for bad debt. As actual storm damage occurs, it would not charge the amounts to expense but would use the actual storm damage costs to reduce the liability on the balance sheet to pay for the storm up to the amount in reserve. The severe storm reserve would accrue interest at Xcel's approved cost of capital so that ratepayers retain the value associated with a prepayment of these funds. Any funds remaining in the reserve account would carry over to the following years. Xcel would define a severe storm as one that is excluded from the Service Quality SAIDI measure.[34] In the alternative, Xcel proposed to increase its test year annual tree trimming expense from $20.9 million to $22.9 million.[35]

44. In the Commission's service quality docket, Commission staff recently noted that Xcel is still reporting a significant number of outages due to insufficient tree trimming. The Commission's recent order in that docket requires Xcel to implement a more comprehensive "circuit based" approach to tree trimming in addition to complying with SAIDI standards (which measure the number of service interruptions per customer per year).[36] The *Service Quality Order* specifically requires Xcel to annually report on its budgeted and actual tree-trimming expenditures on a going-forward basis, identify circuits for which vegetation has not been trimmed in the last five years, and describe its plans to achieve for all circuits what is essentially a five-year tree-trimming/maintenance cycle.[37]

45. The Department opposes the severe storm reserve on the basis that Xcel has not sufficiently differentiated between a "severe" storm and a "regular" storm that would otherwise be managed through the annual O&M budget. The Department also contends that these costs have been built into the O&M budget in the past and that a reserve fund would permit a double recovery. The Department acknowledges, however, that the reporting requirements in the *Service Quality Order* reduce the risk of any over-recovery.[38] Finally, the Department argues the record is insufficient to demonstrate that $2 million is the correct amount for any reserve. The Department also maintains that no increase in the tree-trimming budget is necessary because $20.9 million is sufficient to ensure adequate tree trimming.[39]

46. The record supports Xcel's contention that it needs more funds to address severe storm damage, either through the severe storm reserve or through an increase in its tree-trimming budget. Although the Department maintains the tree-trimming budget increases are high (16% since 1998), the Commission has required Xcel to make substantial improvements in preventing storm-related outages, and despite the budget increases there are still a significant number of service outages that could be reduced through additional tree trimming. The Commission's *Service Quality Order* establishes an annual

process by which the Commission and the Department can monitor Xcel's tree-trimming budget and expenses. Accordingly, the Administrative Law Judge recommends that Xcel's alternative proposal, to increase the tree-trimming budget by $2 million, be accepted.

D. Incentive Compensation

47. Xcel's incentive compensation program is intended to allow Xcel to attract, retain, and motivate employees to achieve its performance objectives. Target annual incentives as a percentage of base salary are set for each eligible employee. Incentives are awarded based on the employee's performance and the company's overall performance. As with most incentive plans, Xcel has the discretion to withhold earned incentive compensation based on its financial performance.[40]

48. In Xcel's 1992 rate case, the Commission allowed Xcel to include in the test year revenue requirement annual incentive compensation subject to a cap of 15% of base salary. Because the company retains the discretion not to pay out any such compensation if it performs poorly, the Commission required Xcel to record all earned but unpaid incentive compensation in rates for future return to ratepayers through a refund mechanism.[41]

49. A 2005 compensation study by the Towers Perrin consulting firm concluded Xcel's incentive targets are well-aligned with those of other utilities. Its total cash compensation levels, including the incentive plan at full target levels, is comparable to that of other utilities but are about 6% below market rates for similar-sized utilities.[42] With a cap of 25% of base salary, Xcel's total cash compensation would be 3% below the market rate for all utilities and 9% below the market rate for comparably sized utilities.[43]

50. Xcel has not, however, paid out incentive compensation at target levels. In 2000 and 2001, Xcel paid incentive compensation above target levels; in 2002, due to the poor financial performance of NRG Energy, Inc., Xcel paid 50% of earned amounts to most employees and no incentive payments to executives and upper level management. In 2003, no target incentives were set, although incentive compensation was paid in excess of the amount budgeted. In 2004, incentive compensation was paid at about half of targeted levels, and in 2005 it was paid at about one third of targeted levels.[44] On average, Xcel actually paid incentive compensation at 58% of target levels for the years 2002-2005.[45] Through the refund mechanism, Xcel refunded $1.4 million to ratepayers for the 2002 plan year, and it will refund about $655,411 for the 2004 plan year. Data for 2005 is not final.[46]

51. For the test year, Xcel has budgeted that it will pay incentive compensation at 27.1572% of target level. Xcel has proposed that incentive compensation be set, however, at the amount it would pay if 100% of target level were met, subject to a cap of 25 percent of employee base salary, and further

subject to the refund mechanism established in the last rate case. This amounts to approximately $9,354,666.[47] All long-term incentive payments are excluded from this calculation.[48]

52. The Department proposes to decrease this figure by one of two methods. The first alternative is to use the test year budget to set incentive levels, subject to a cap of 15% of base salary. This would result in a reduction of $6,952,345. The second alternative is a somewhat smaller reduction ($5,854,000) based on using for the test year expense an average of 2002 actual, 2004 actual, and 2006 budgeted amounts, net of individual incentive compensation in excess of 15% of base pay. The Department did not include data for 2003 and 2005 because Xcel did not have data necessary to determine the amount of incentive in excess of 15% of base salary for those years.[49]

53. Neither one of these proposals is entirely appropriate in terms of establishing a representative test year expense. Xcel's proposal sets incentive compensation at a level substantially greater than it has actually paid since the NRG difficulties in 2002 (with the exception of 2003, a year in which no target incentives were set). The expense proposed by Xcel would be subject to the refund mechanism, but the test year expense should still be set at a realistic number that is not guaranteed to over-recover this expense. The Department's proposal would set test year expense at an amount substantially lower than Xcel actually paid in any year from 2000-2005. In addition, the Department's proposal would limit incentive payments to a total of 15% of base salary.

54. With regard to the base salary cap, the Administrative Law Judge is persuaded by Xcel's evidence that a cap at 25% of base salary is consistent with compensation packages in the utility market and is necessary to make Xcel's total compensation package competitive.[50] Furthermore, denial of incentive compensation at this level would inappropriately provide Xcel with the incentive to restructure compensation toward increases in base salary, which are recoverable in rates, and which in turn would increase the costs of other benefit plans that are tied to base salary.[51]

55. The Department's proposal to use the budgeted amount for 2006 is not tied in any way to Xcel's historical performance, and there is no information available in the record to determine how budgeted numbers compare to actual payouts in past years. The Department's other proposal, to use actual expense levels for certain years, cannot be adjusted to reflect actual performance in all years because Xcel does not have the data needed to make the necessary adjustments to the Department's method.

56. Xcel argues that if all actual payouts are averaged from 2000-2005, it has paid out at 79% of target levels.[52] The Administrative Law Judge agrees with the Department, however, that the payouts for 2000-2001 should not be averaged into the test year expense, because these years preceded the NRG

difficulties, and the incentive payouts during that period were much greater than any Xcel has made since then.

57. The Administrative Law Judge recommends that the Commission modify Xcel's proposal by basing incentive compensation on target levels adjusted to reflect actual payouts for 2002-2005, because there is information in the record as to how target levels have corresponded to actual payouts over this period. The Department does not dispute that the target levels are set at reasonable amounts compared to the industry as a whole. The adjustment would work as follows: The 2006 target incentive level is $10,042,932 for the Minnesota jurisdiction.[53] Xcel's historic payout for 2002-2005 has been 58% of target level.[54] The test year pre-cap expense—based on Xcel's history of achieving 58% of target—would thus be $5,824,900.[55] Xcel has calculated that the amount to be excluded to reflect a cap of 25% of base salary is $689,266.[56] When this amount is subtracted from the pre-cap expense, the test year expense would be $5,135,634.[57] The Administrative Law Judge also recommends that the Commission continue the requirement that all incentive earnings be tracked and subject to the refund mechanism.

E. Private Independent Spent Fuel Storage Installation Investments

58. In 1994 and again in 2003 the Minnesota legislature authorized Xcel to store nuclear waste at Prairie Island, subject to a number of conditions. One of those conditions was that Xcel seek to secure out-of-state storage for spent fuel.[58] To that end, Xcel participated in the development of a private independent spent fuel storage installation (ISFSI).[59] In 1997, Xcel and seven other utilities formed a limited liability company, Private Fuel Storage LLC (PFS), for the purpose of obtaining authorization to site and construct a private ISFSI within the Goshute Indian tribal land in Utah. The NRC recently granted the necessary authorization.[60] Construction of the project is on hold indefinitely, however, pending a final determination of legal and legislative challenges.[61]

59. Xcel has invested $23,302,299 in that facility.[62] Because the amount expended was for the development of a storage facility, the amounts were treated as an investment in the facility and were recorded to an investment account, FERC Account 123.1.[63]

60. With the construction of the facility on hold for an indeterminate time, Xcel proposed that the start-up investment costs be recovered without placing the investment into rate base. The Department agreed that recovery of this investment was reasonable and that the investment should be amortized. The Department identified one concern with the beginning balance, with which Xcel agreed. Thus, the undisputed amount to be amortized is $23,302,299.[64]

61. The only disputed issues related to the recovery of these investment costs involve the amortization process. Xcel originally proposed using a three-year amortization period, whereas the Department proposed that

the investment be recovered over ten years. Xcel now proposes recovery over six years. In addition, the parties disagree about whether the Commission should address, at this time, rate consequences after the investment has been fully amortized. The Department agrees that if Xcel files an electric rate case before the deferred amount is fully amortized, any unrecovered balance should be recovered in that future rate case.[65]

62. The Department proposes a ten-year amortization period because the investments were made over a ten-year period; the investments are not being written off, and it is uncertain at this time whether the facility will become necessary; and the costs of the facility should be paid by the customers who benefit from low nuclear power costs. Because Xcel's nuclear facilities may be relicensed and the life of the facilities may be extended, the Department contends that the ten-year period is reasonable. In addition, the Department argues that Xcel may over-recover if a shorter amortization period is used and Xcel does not come in for another rate case in that timeframe. The Department also assumed incorrectly that because this amount was booked as an investment, Xcel was including it in rate base, where it would earn a return.[66]

63. Xcel contends that a ten-year recovery is an unnecessarily long period to reduce the rate impact of these costs. Xcel anticipates that it will file two rate cases in the next six years.[67]

64. There is no exact formula for establishing the appropriate length of the amortization period.[68] With regard to other issues, the Department advocated using a four-year amortization period, as that is the historical average length of time between rate cases. The fact that Xcel made the investment over a ten-year period means that Xcel has already waited that long to recover some of its investment, without any return. The Department's proposal to wait another ten years before it is fully recovered is unreasonable.

65. The Department also proposed a sunset on any cost recovery once the ten-year period is completed with a rate reduction being required at that time.

66. Xcel proposes waiting until the next rate case to make a determination of the appropriate rate treatment for the period after full amortization occurs. While Xcel agreed that major special rate allowances may justify special treatment to prevent the overall rates from becoming unfair, it noted that normally rates are not adjusted each time a cost ceases. Because either amortization period provides sufficient likelihood that there will be an intervening electric rate case, this issue does not have to be decided in this proceeding.

67. The Administrative Law Judge concludes that the investment in the ISFSI was reasonable in light of the legislative direction to develop an out-of-state spent fuel storage location. It is also reasonable to amortize the recovery of

the investment without inclusion in rate base. A six-year amortization period is reasonable because Xcel has already waited a substantial number of years to recover its investment, with no return, and because the rate impact of using an amortization period shorter than ten years is not significant.[69] There is no need for the Commission to determine at this time whether to impose a sunset on cost recovery once the amortization period expires, because it is reasonable to anticipate another rate case before the amortization period expires, and the Commission will have additional information available to it in that rate case on the impact such a sunset would have on rates.

F. Time of Use Pilot Project Expenses

68. In 2001, the Commission initiated an investigation into developing a Time-of-Use (TOU) Program for Xcel's residential electric customers.[70] In the course of that proceeding, the Commission ordered Xcel to design TOU rates, which would charge consumers different amounts for electricity consumed at different times of day. In a report filed on April 9, 2002, Xcel proposed three scenarios for initiating TOU rates. Based on the experience reported in a similar program in the state of Washington, which showed that residential customers paid higher electric bills than they would have paid without the program, the Commission terminated the pilot project.[71]

69. Xcel later petitioned the Commission, seeking approval of deferred accounting treatment so that these expenses could be recovered in the next rate case. Because Xcel had incurred these costs at the Commission's direction and because these costs directly benefited ratepayers, the Commission concluded the costs were reasonable, and it expressly authorized deferral of these expenses.[72] The Commission also accepted the Department's recommendation that the appropriate amortization period should be set in Xcel's next rate case.[73]

70. In this case, Xcel originally sought recovery of these expenses using a three-year amortization period. The Department recommended use of a four-year, rather than three-year, amortization period, but otherwise had no objection to Xcel's proposed recovery of this expense. Xcel accepted the Department's recommendation to use a four-year amortization period and is requesting recovery of $2,469,247 in deferred TOU program costs.[74]

71. The OAG has consistently opposed the TOU program. The OAG asserts that because the Commission terminated the TOU program, there was no ratepayer benefit that would justify allowing Xcel to recover these costs. Specifically, the OAG argues that Xcel cannot recover the start-up costs associated with the TOU Program because those costs were not "used and useful in service to the public."[75] The OAG contends that recovery of these costs is inconsistent with case law and previous Commission precedent. It further argues that the Commission should deny recovery of approximately $1.6 million in costs associated with Deloitte Consulting, based on the OAG's assertion that these costs were incurred in violation of the rules of the Securities

and Exchange Commission (SEC), which prohibit auditors from performing "management activities" for the companies they audit.

72. In its *TOU Order*, the Commission expressly found that Xcel's costs, including the Deloitte Consulting costs, were reasonable, and it authorized Xcel to recover the costs in its next rate case. The Commission also expressly rejected the OAG's arguments that these costs were unreasonable or that they were incurred illegally.[76] Xcel should be permitted to recover these costs in this case using the four-year amortization period recommended by the Department.

G. Settled Operating Income Issues

1. Asset-Based Margin Revenues

73. Xcel initially proposed that asset-based margins from inter-system sales be recognized in the fuel clause adjustment (FCA) and that 100% of all asset-based margins be flowed through up to the Minnesota jurisdictional share ($16.9 million) of the $21.9 million forecast level for the 2006 test year. Xcel proposed that all margins achieved above the test year forecast level be shared equally between it and its customers (50% to customers through the FCA and 50% retained by Xcel). Several parties—the OAG, the Large Industrial Group, the Commercial Group, ECC, the Chamber, and the Department—objected to this proposal.

74. In general, the objecting parties argued for a higher threshold before sharing margins with shareholders or for a sharing allocation more favorable to customers than the 50/50 allocation proposed by Xcel.[77] Ultimately, all objecting parties, except the Department, entered into a settlement agreement to resolve their concerns related to this issue. The settlement reflects the consensus view of these parties that customers should receive a substantially larger share of asset-based wholesale margins than the 50% initially proposed by Xcel.[78]

75. The settlement provides for the return to customers of 100% of the Minnesota jurisdictional share of margins from inter-system sales of excess generation through the FCA, as a credit to fuel and energy expense, with no base rate reduction.[79] The settlement also provides for the return through the FCA of 80% of the Minnesota jurisdictional share of asset-based margins from intersystem sales derived from ancillary service obligations (e.g., spinning reserves).[80]

76. The settlement reflects a reasonable compromise that provides the potential for significant additional benefits to customers above those provided under Xcel's initial proposal, while allowing Xcel to avoid the volatility in annual results from what are essentially opportunistic sales activities that can vary widely depending on price and unit availability. The settlement also recognizes additional stipulated facts that support the need to provide a proper incentive to

Xcel with respect to certain types of wholesale market transactions that are more difficult to arrange and for which Xcel bears more significant congestion risk.

77. The Department proposed that test year revenues from wholesale sales be set at $22.2 million for the jurisdiction, with revenues above that amount to be shared 85% to retail customers and 15% to Xcel.[81] While the Department did not enter into the settlement, and therefore its proposal is an alternative for the Commission to consider, the Department also indicated that it did not oppose the settlement and would not promote its alternative to the Commission.

78. All the parties that raised concerns regarding Xcel's MISO Day 2 proposal have either entered into, or indicated they do not oppose, this settlement. Given that no party provided any definitive facts to demonstrate the best level of sharing or superior approach to including asset-based margins in rates, this consensus agreement among the concerned parties reflects a result that is both reasonable and in the public interest.

2. Non-Asset-Based Margin Revenues

79. With respect to non-asset-based margins, which are generated by trading activities not associated with Xcel's generation resources, the settlement provides that 25% of these margins will be flowed through the FCA to customers with 75% retained by Xcel. This settlement reflects the Xcel alternative that the Department supported in its testimony.[82] Importantly, the settlement provides that ratepayers will not bear any risk of any net annual loss on non-asset based sales. The customer sharing agreed to by the parties is in recognition of the cost of labor and systems included with base rates associated with conducting these non-asset based transactions, not as encouragement for Xcel to engage in such transactions. Xcel remains free to determine whether to continue in this business activity. The agreement is supported by the Department and is reasonable.[83]

3. MISO Day 2 Costs

80. Xcel initially proposed recovering all MISO Schedule 16 and 17 costs, totaling $8,941,000, through the fuel clause.[84] The Department opposed this proposal and recommended instead: (i) adjusting these MISO Day 2 costs down from $6.53 million on a Minnesota jurisdictional basis to $5.92 million; (ii) moving recovery of these MISO Day 2 costs from the FCA to base rates; (iii) deferring recovery of 50% of MISO Day 2 costs until better information is available in Xcel's next general rate case; and (iv) requiring that Xcel show benefits of MISO Day 2 in a future rate proceeding.[85] In setting interim rates, the Commission moved these costs to base rates.[86]

81. In settlement of disputes related to MISO Day 2 cost recovery, Xcel agreed with the OAG, the Chamber, the Large Industrial Group, and the Commercial Group to adopt the Department's position.[87] The parties have also agreed that this settlement would not prejudice positions to be taken on the 30

other types of charges being addressed in the pending MISO Docket.[88] Further, the parties have agreed that the deferral recommended in Ms. Campbell's testimony is effective as of January 1, 2006.[89]

82. This settlement is supported by the Department and reflects a reasonable resolution of MISO Day 2 Schedule 16 and 17 cost recovery issues, given that the MISO market was working through implementation issues during the development of the record of this proceeding.

4. Forecast for Fuel and Purchased Energy Costs

83. The Chamber raised concerns regarding the level of 2005 charges flowing through Xcel's FCA mechanism.[90] Xcel responded that the increases in the FCA were caused by a multitude of factors and that it was not simply related to the fact that Xcel participated in the Day 2 market.[91] Xcel subsequently entered into a settlement agreement with the Chamber and the Large Industrial Group.

84. The settlement includes several commitments by Xcel intended to provide customers with more information and analysis that will enhance the ability of customers to plan for and manage volatility in fuel costs.[92] The additional information and analysis will include more discussion on Xcel's plan for hedging fuel or energy purchases and more analysis of how Xcel will try to mitigate volatility, cover risks associated with planned outages and optimize congestion cost hedging. The additional information will also include a dollar per megawatt hour price that will show the rolling 12-month average cost quarterly based on expected market conditions.[93]

85. This settlement will benefit customers by providing them with information they do not currently receive and enhancing their ability to manage their operations in response to a significantly more volatile fuel and energy market. The settlement is reasonable and in the public interest.

H. Operating Income Issues Resolved Through Testimony

1. Nuclear Decommissioning Expense

86. Xcel adopted all of the Department's recommendations regarding the implementation of the Commission's Order in Docket E-002/M-05-1648 regarding the accrual for decommissioning funds.[94] Xcel identified the corresponding adjustments to the test year end-of-life nuclear fuel expense and the deferred tax expense.[95] No party opposes Xcel's proposal as modified to incorporate the Commission's Order. Xcel's modified proposal is reasonable and in the public interest.

2. Transformer Gain on Sale

87. Xcel recorded the sale of its transformer at the Black Dog generating plant as having occurred at its net book value of $250,000 and removed that amount from rate base.[96] The Department, however, contended that the sale should reflect the fair market value of $376,000 as indicated by the manufacturer, VTC, resulting in an approximately $54,000 reduction in the test year revenue requirement.[97] Xcel accepted the Department's recommended adjustment.[98]

3. Merger Savings

88. As previously ordered by the Commission,[99] Xcel presented testimony showing that the target savings level for the proposed test year is $41.9 million and that those savings have been achieved.[100] No party filed any testimony in opposition. Xcel met its burden to demonstrate merger savings, and it should not have to continue making this affirmative showing in future rate cases.

4. Advertising Expense, Economic Development and Marketing Expenses

89. Xcel proposed including in the test year $1,465,682 for costs relating to advertising, based on the statutory criteria contained in Minn. Stat. § 216B.16, subd. 8.[101] No party contested the inclusion of these costs in rates, and the Department agreed that Xcel's proposal related to advertising costs complies with Minn. Stat. § 216B.16, subd. 8.[102]

90. Consistent with prior rate cases, Xcel proposed the recovery of 50% of its economic development costs through an additional $52,464 in test year administrative and general (A&G) costs.[103] No party contested the inclusion of these costs, and the Department supports Xcel's proposal to recover 50% of its economic development expenses.[104] It is reasonable to include in rates the $52,646 amount proposed by Xcel and supported by the Department.

91. The Department opposed recovering marketing expenses without demonstrating their reasonableness.[105] Xcel, however, did not include any marketing expenses in the test year.[106] Therefore, it was not necessary to determine the reasonableness of such expenses.

5. State Energy Policy Rider

92. Xcel proposed to build into base rates the recovery of costs currently recovered through the State Energy Policy (SEP) Rider. The Department opposed this proposal.[107] The Department noted, however, that this issue is resolved if Xcel does not move SEP cost recovery to base rates at this time. Xcel accepted the Department's request.[108]

6. Depreciation Expense

93. Xcel initially proposed a depreciation expense reflecting the depreciation rates last certified by the Commission in 2005. The Department proposed using the depreciation rates in the pending 2006 Commission docket to determine the depreciation expense in this proceeding, and Xcel agreed to accept the Department's proposal.[109] Adopting the Department's recommendation will reduce the electric utility depreciation expense for the Minnesota jurisdiction by $556,000.[110] No party opposes this revised depreciation expense.

7. Municipal Power Sales

94. In its Surrebuttal Testimony, the Department expressed concern that, with respect to Xcel's wholesale power sales to municipal utility customers, Xcel might be collecting dollars related to retail rate trackers, but not reflecting the revenues in the tracker accounts.[111] In response, Xcel presented additional testimony and information to explain how wholesale revenues and costs are reflected in Xcel's test year cost of service.[112] The additional testimony and information provided by Xcel demonstrated that the rates paid by wholesale municipal customers are indexed to Xcel's retail electric rates, but that customers do not pay the tracker charges. Accordingly, the Department has indicated that its concerns on this issue have been resolved, and that a compliance report is no longer necessary.[113] No other party expressed concerns regarding this issue. Therefore, no adjustment to the test year cost of service or any tracker is appropriate, and no compliance filing is necessary.

8. Job Creation Act

95. Xcel proposed, as part of its compliance filing, to make an adjustment to reflect the effect of the Job Creation Act.[114] While the final amount of the adjustment has not been determined, Xcel estimates that it would reduce the revenue requirement by approximately $435,000.[115] The level of the credit to be included in rates is dependent on production income and thus must be calculated after the Commission's final determination in this proceeding. The Department agrees with this proposal, and no party disagrees with it.[116]

9. Sales and Customer Forecasts

96. Xcel provided the sales and customer forecasts used in preparing the jurisdictional cost of service.[117] With the exception of how to treat future revenues related to Flint Hills' return as a full-requirements customer, the Department supported Xcel's sales volumes and customer forecasts.[118] The proper treatment of future Flint Hills revenues and costs is discussed above.

10. MISO Day 1

97. Xcel initially proposed recovering all of its MISO Day 1 (MISO Schedule 10) costs, noting that these expenditures provide benefits to ratepayers through enhanced transmission reliability, improved transmission planning and

regional planning by MISO.[119] No party opposed the concept of MISO Day 1 recovery, but the Department recommended a downward adjustment to Xcel's estimate of these costs based on its determination that Xcel had initially overestimated them.[120] Xcel accepted the Department's adjustment and, accordingly, MISO Day 1 costs should be adjusted downward by $349,000.[121] This adjustment resolves the only dispute with respect to MISO Day 1 costs.

11. Test Year Amortizations

98. Xcel and the Department are in agreement that a four-year amortization period should be used for the following six items: (1) Rate Case Expense Amortization; (2) Income Tax Tracker Amortization; (3) Time of Use Study Amortization; (4) Levee Station Amortization; (5) MN Emissions Allowance Amortization; and (6) E002/M-05-1471 Deferred Accounting Amortization.

99. In its initial testimony, Xcel proposed a three-year amortization period based on its judgment that future rate cases will be filed more frequently than in the past. The four-year period recommended by the Department is based on the historical average period between rate cases.[122] Xcel agreed to use the four-year amortization period.[123] Because the actual period between rate cases cannot be predetermined, Xcel also proposed that any unrecovered or unrefunded balances be carried over into a future rate case.[124] The Department opposed this proposal.[125] Xcel then withdrew its request to have unrecovered or unrefunded balances reduced to zero in the event a rate case is filed in less than four years.[126]

12. Cost Allocations

100. Xcel provided testimony concerning NSP-MN accounting policies and procedures with regard to assignment and allocation of costs among all relevant legal entities, utilities, jurisdictions and non-regulated business activities.[127] Neither the Department nor any other party objected to these assignments and allocations.[128] Therefore, this matter is uncontested, and Xcel's methods for assigning and allocating costs should be approved.

III. COST OF CAPITAL

101. Xcel recommended an overall rate of return (ROR) of 9.04%, including a return on equity (ROE) of 11.0%.[129] The Department's final recommendation is an overall ROR of 8.86%, including an ROE of 10.64%.[130]

A. Capital Structure

102. Northern States Power Company (NSP-MN) is a separate corporation that has its own capital structure and issues its own debt. NSP-MN is a subsidiary of Xcel Energy, Inc. (XEI). NSP-MN files its own 10-K and 10-Q statements with the SEC.[131]

103. Xcel's proposed capital structure and weighted cost of capital are as follows:[132]

Capitalization	Percentage of Total Capitalization	Cost	Weighted Cost
Long-term Debt	45.57%	7.08%	3.23%
Short-term Debt	2.76%	4.71%	0.13%
Common Equity	51.67%	11.00%	5.68%
Total	100%		9.04%

The percentage of common equity in the capital structure was adjusted from 51.38% to 51.67% to reflect the MERP Settlement approved by the Commission's March 8, 2004, Order in Docket No. E002/M-02-603.[133]

104. The Department agreed with Xcel that this is the appropriate capital structure, including adjustments.[134] No party disputed the capital structure proposed by Xcel and concurred in by the Department.

B. Cost of Short-Term Debt

105. Xcel proposed a 4.71% short-term cost of debt. The Department concurred that this is the appropriate short-term cost of debt.

C. Cost of Long-Term Debt

106. Xcel proposed a long-term cost of debt of 7.08%, which reflects two adjustments. First, the overall cost of debt was decreased from 7.19% to 7.01% to reflect the 1.957% decrease in the cost of tax exempt bonds issued by NSP-MN in 2002. Second, the overall cost of debt increased from 7.01% to 7.08% to reflect the forecasted debt cost applied under the MERP Settlement.[135]

107. Xcel provided evidence regarding the costs of the debt issuances by NSP-MN during the period between June 2002 and March 2004.[136] It analyzed both the impact of NRG on NSP-MN's credit ratings and the possible impact on the cost of debt.[137]

108. NSP-MN's credit rating was affected by the several factors, including NRG's financial difficulties, severe economic trends affecting the entire electric utility industry, and tightening of rating agency criteria.[138] The reduction in NSP-MN's credit ratings was the result of all of these factors.[139]

109. The prevailing rating for integrated utilities (such as NSP-MN) changed from AA in December 2000 to BBB in October 2002. The average rating downgrade for electric industry senior unsecured debt was from AA to BBB+, nearly two full notches.[140] NSP-MN's downgrade was less severe than the industry average, from BBB+ to BBB-, less than one full notch.[141]

110. NSP-MN took several steps to mitigate the effect of its credit rating downgrades. These steps included the issuance of very long-term (40 year) retail notes; using secured senior debt, in place of unsecured debt; and using intermediate term secured debt.[142]

111. The weighted average cost of the NSP-MN debt issued during the period of NRG financial difficulties was 7.119%, after an increase of the interest rate of a tax exempt debt issuance (for purposes of analysis) to a taxable equivalent rate.[143]

112. That 7.119% weighted average rate is slightly higher (about 12 basis points) than the Standard and Poor's Utility Bond Index (S&P Index) A-rated average of 6.994%, and considerably lower (about 61 basis points) than the S&P Index BBB-rated average of 7.730%.[144]

113. The S&P Index provided a comparable term comparison, as the weighted average maturity of the portfolio of NSP-MN debt issued during the period of NRG financial difficulties was 14.75 years,[145] and the S&P Index includes debt with an average maturity of 15 years.[146]

114. NSP-MN also proposed an adjustment to reduce (by 1.957%) the interest rate of the tax exempt (Becker Bond) issue, which had not received the lower (tax exempt) interest rate that had been received in prior tax exempt issuances by NSP-MN.[147] That adjustment was based on the lower tax exempt interest rate differential that NSP-MN had obtained in its prior tax exempt issuances.[148] The result, after that adjustment, was a 6.717% weighted average interest cost for the portfolio of NSP-MN debt issued during the NRG period.[149]

115. The 6.717% weighted average interest cost was 28 basis points lower than the A-rated index and 1.01% lower than the BBB-rated index. This fact is particularly significant because the predominant integrated index rate is BBB, and NSP-MN had not had a pure A-rating before the NRG financial difficulties arose (NSP-MN had a split A/BBB rating).[150]

116. The terms and maturities of a company's prior issuances have an effect on the available terms and maturities of subsequent issuances, which affects costs. As a result, the costs of the group of debt issuances (the portfolio) are interrelated, and analysis of the overall cost of a portfolio is the only reasonable approach to reflect the interrelationship.[151] In particular, NSP-MN's issuance of the very long-term (40 year) retail notes in 2002 enabled it to issue intermediate term (3-year and 7-year) secured debt in 2003.[152] It would be unreasonable to ignore the lower than A-rated cost of the intermediate term debt.

117. The Department agreed with Xcel's calculation of the long-term cost of debt (including the adjustment to the tax exempt bonds).[153] Excelsior Energy's expert concurred that there was no adverse impact on NSP-MN's cost of debt as a result of NRG.[154]

118. The OAG expert asserted that NSP-MN's cost of debt had been adversely impacted by NRG.[155] He acknowledged that he had not conducted any independent analysis of the cost-of debt issued by NSP-MN.[156] He stated that his conclusion was based only on changes in Xcel's credit rating.[157] He had no specific recommendation for any adjustment to NSP-MN's cost of debt.[158]

119. The OAG expert initially addressed only two of the four debt issuances by NSP-MN.[159] Both of these debt issuances were issued at or below the average yield on A bonds in the S&P Index. As noted above, however, the BBB average became the prevailing rating for public utilities during 2002, even for utilities that had formerly been AA-rated (which exceeded NSP-MN's split A/BBB pre-NRG rating).[160]

120. The OAG expert also contended that NSP-MN's 3- and 7-year debt is short-term debt that should not be included in a comparison with the S&P A-rated utility bond index.[161] He acknowledged, however, that the standard definition of "short-term debt" is debt with a term of less than one year,[162] and 3- and 7-year debt would not fit the definition of short-term debt.[163] This debt was properly included in the NSP-MN's portfolio for purposes of comparison to the S&P long-term bond index.[164]

121. The OAG expert's opinions to the effect that NRG had adversely impacted Xcel's long-term cost of debt are unpersuasive. He was not able to substantiate that NRG's difficulties had any effect beyond some impact on Xcel's credit rating, and he was unable to quantify the effect he maintained it had.

122. The Administrative Law Judge recommends that the Commission use Xcel's proposed long-term cost of debt of 7.08%.

D. Return on Equity

123. The Discounted Cash Flow (DCF) model is widely used to determine the returns that utility investors can earn in utility stocks.[165] The DCF model is based on the theory that a stock's price represents the present value of all future expected cash flows.

124. The Capital Asset Pricing Model (CAPM) is a risk premium approach that specifies the required ROE for a given security as a function of the risk-free rate of return, plus a risk premium that represents the non-diversifiable risk of the security.

125. Xcel originally proposed an ROE of 11%, based on the DCF model and the CAPM.[166] Its analysis included two groups of electric utilities whose financial metrics it found to be comparable to NSP-MN and whose operations were primarily in the Midwest, which has market and regulatory characteristics similar to Minnesota. Use of an 11% ROE results in a 9.04% overall ROR.[167]

126. Xcel used a 360 trading day averaging period ending September 30, 2005, to determine the dividend yield component of the DCF model.[168] Xcel also included a flotation cost adjustment to reflect the costs of prior public issuances of common stock.[169]

127. Xcel argued that the range of reasonable ROEs was from 10.50% to 11.20% and recommended an ROE of 11.00%, based on market conditions, including expectations of rising interest rates.[170]

128. The Department used a DCF analysis, verified by a CAPM analysis.[171] It analyzed a group of domestic electric utilities (electric comparison group, or ECG); a group of combination electric and gas utilities (combination comparison group, or CCG); and XEI. The Department's expert applied weights of 25% for Xcel Energy, 50% for his ECG, and 25% for his CCG to determine the specific DCF recommendation.[172] He also used a 30 day (21 trading day) period ending January 5, 2006 to determine the dividend yield of the DCF model, as well as a flotation cost adjustment.[173] The Department's original ROE recommendation was 10.54%.[174]

129. The OAG argues that the Commission should re-evaluate the manner in which ROEs are determined and should use instead NSP-MN's actual ROE, or perhaps incorporate actual ROEs for proxy groups into the DCF analysis.[175] The OAG does not, however, propose using any specific number. The Department opposes this suggestion, arguing that rates established in a rate case apply prospectively, not retroactively, and that use of historical data does not represent the periods for which the ROE will be in effect. Furthermore, there is no guarantee that a utility will earn the authorized rate of return—for any given year a utility may earn above or below its authorized rate of return, depending on the impact of weather on electricity usage, the general economic environment, and company-specific returns.[176]

130. Xcel and the Department were in agreement concerning the method to calculate the dividend yield component of the DCF model (including one-half of the expected long-term growth rate); the use of a flotation cost adjustment and the method used to calculate that adjustment; the growth rate estimates used in the DCF model; and the need to update data to obtain the most current available data.[177]

131. Xcel and the Department disagreed about the following matters: (i) Xcel's and the Department's comparison groups included several of the same companies, but there were several differences; (ii) the Department used the weighted average of three ROE estimates to arrive at its result, whereas Xcel examined both the midpoint results and future market conditions to make his recommended ROE; (iii) Xcel used a 360-day averaging period to determine the dividend yield, while the Department used a 21-day period; (iv) Xcel and the Department did not agree in regards to some components of the CAPM analysis, including the term of the Treasury Note to determine the risk free rate (the

Department maintained it was the 5-year rate, Xcel maintained it was the 10-year rate); and the risk premium calculation.[178]

132. Xcel updated its analyses using both 20 and 360 trading day averaging periods ending March 10, 2006, and included various sub-groups of both Xcel's and the Department's proxy groups.[179] The results of Xcel's updated DCF analysis using a 20-day period were are very similar to the results of the 360-day period.[180] Xcel's revised DCF results based on the 20-day period resulted in an ROE range of 9.91% to 11.46%, with a mean of 10.69%.[181] Xcel also updated its CAPM analysis, which led to an 11.24% mean ROE.[182]

133. The Department updated its analysis to include data for the 21 trading days ending March 28, 2006.[183] The Department's updated analysis resulted in an ROE range of 9.87% to 11.57%, with a mean of 10.64%.[184] Its CAPM analysis led to a mean ROE of 10.81%,[185] which was used to confirm the DCF-based 10.64% ROE recommendation.[186]

134. Xcel's and the Department's updated DCF results are summarized as follows:

	Low	Mean	High
UPDATED DCF RESULTS			
Xcel 20-day	9.91%	10.69%	11.46%
Department 20-day	9.87%	10.64%	11.57%

135. Xcel maintains that while securities prices may reflect "some" element of projected interest rates, it is not reasonable to assume that all such changes are incorporated in current prices.[187] Accordingly, Xcel argues that use of an ROE at the midpoint of the range is unlikely to provide a sufficient return and that it is appropriate to use an ROE approximately halfway between the mean and the high end of its DCF range. The Department believes that the market data (current dividend yields as well as forecasted growth rates) fully reflect all significant data, including increasing interest rates, making further subjective judgment in the use of DCF results unnecessary.[188]

136. The Administrative Law Judge recommends that the Commission use the ROE recommended by the Department (10.64%), which produces a ROR of 8.86%. The Department's recommendation is well-grounded and transparent. Xcel has failed to substantiate that its basis for recommending an ROE above the mean of its DCF results is reasonable.

137. Xcel and the Department agree that use of comparable proxy groups and use of forward-looking data to determine ROE effectively remove NRG's financial difficulties from the ROE determination for NSP-MN.[189]

IV. INCOME TAXES

138. Based on its proposed revenue requirement, Xcel has calculated a test year federal tax expense of $88.171 million and state tax expense of $27.37 million. The OAG recommended reducing Xcel's test year income tax expense by approximately $100 million by use of the average of prior years' consolidated income tax results of the parent company, Xcel Energy Inc. (XEI), and all of its subsidiaries, regulated and unregulated.[190] Those results included substantial income tax deductions that were incurred by Xcel Energy Wholesale Group, Inc. (Wholesale), an unregulated subsidiary of XEI. Those deductions arose from 2003 and 2004 losses from unregulated investments in NRG Energy, Inc. (NRG), which was owned by Wholesale.

A. The Stand-Alone Approach

139. Xcel used the stand-alone approach in this proceeding, as it has done in each of its prior rate cases and in all of its financial reporting to the Department and Commission.[191] The stand-alone method is one part of the process by which the regulated costs of service are systematically separated from unregulated costs. The stand-alone method determines the regulated income tax expense, which arises solely from regulated revenues and regulated expenses that are allowed recovery in rates. The stand-alone method is intended to accurately reflect the cost of utility service because it matches regulated income tax expense to the regulated revenues and expenses (which lead to the income tax expense). The stand-alone method also supports the policy of maintaining financial separation between regulated and unregulated businesses so that utility customers are responsible only for the costs of providing utility service. The Commission has used the stand-alone method in the past because, if properly implemented, it accurately reflects the cost of providing utility service from both regulatory and financial perspectives.[192]

140. All aspects of the utility cost of service, not just income taxes, are isolated using this same basic approach, beginning with the separation of the costs of regulated operations from the costs of unregulated operations (often of utility affiliates), followed by separating costs by state jurisdiction (and type of regulated service), and finally isolating only those costs that are eligible for rate recovery. More than a decade ago the Commission adopted explicit and specific cost separation requirements to prevent cross subsidization between regulated and unregulated operations.[193]

141. Xcel's test year income tax expense was based solely on the regulated Minnesota electric revenues and expenses for the 2006 test year. Regulated income tax expense (like any income tax determination) is a byproduct of test year revenues and expenses.[194]

142. From a financial perspective, the stand-alone method can be used to accurately determine income tax expense because tax expenses are also based on accruals, not cash payments. The stand-alone method is consistent with both Generally Accepted Accounting Principles (GAAP), including paragraph

40 of Financial Accounting Standard (FAS) 109, which describes the financial accounting treatment for income tax expense of affiliates;[195] and SEC reporting requirements, including NSP-MN's Form 10-K Reports that have reflected its income tax expense, determined on a separate company basis for every year from 2000-2005.[196]

143. The separate return method complies with FAS 109 because it allocates current and deferred taxes to members of the group by applying this Statement to each member as if it were a separate taxpayer.

144. A separate return calculation uses the same approach at the affiliate company level as the stand-alone method uses at the jurisdictional utility level: separate entities and separate utility operations are treated as if they were separate tax-payers.

B. Use of a Consolidated Return

145. Xcel and all other Minnesota utilities participate in consolidated income tax returns (including the former Northern States Power Company before the 2000 merger that created XEI).[197] Participation in a consolidated income tax return has no effect on the use of the stand-alone method. There is nothing inappropriate about use of a consolidated income tax return by a utility; consolidated returns are permitted as a matter of federal tax policy. Nor does NSP-MN's participation in a consolidated group impact the calculation of the income tax expense associated with providing utility service.

146. Under a consolidated income tax return, a utility with taxable income owes a tax liability to the IRS that is based on its separate company tax return calculation.[198] An affiliate with a tax loss is owed a refund from the IRS. Through the use of a consolidated income tax return, the IRS allows a netting of the tax liability of one affiliate due to the IRS and tax refunds due from the IRS to another affiliate.[199] That netting can result in a full offset so that no payment is made to the IRS by the consolidated group; however, the underlying tax liability of the utility remains and is determined on the basis of its separate company taxable income.[200]

147. XEI's consolidated federal income tax returns demonstrate that NSP-MN has had an income tax liability, based on its separate company taxable income, for each year from 2000 through 2004.[201] (The 2005 returns are not completed.) NSP-MN's 10-K reports confirm that NSP-MN has had significant federal and state income tax expense for each of 2001 through 2005.[202]

148. NSP-MN pays the amount of its tax liability to XEI.[203] NSP-MN's payments to XEI are equal to NSP-MN's income tax liability owed to the IRS based on its separate company taxable income. NSP-MN would pay the same amount to the IRS as a separate tax return filer.[204] Thus, whether NSP-MN files

a separate income tax return or is included in a consolidated income tax return has no effect on ratepayers.

C. NRG Losses

149. The XEI shareholders lost approximately $3 billion in connection with their investment in NRG.[205] The primary components of that loss were cash investments; XEI stock issued to acquire publicly held NRG shares (subsequently lost in the NRG bankruptcy); and cash payments in that bankruptcy proceeding.[206]

150. The Internal Revenue Code permits investors who experience such losses to take a tax deduction, which is intended to encourage investment by mitigating the impact of investment losses.[207] The NRG loss leads to a tax deduction, not a tax credit. Thus, the XEI shareholders will not obtain a full recovery of their losses.[208]

151. The value of the NRG-based tax deduction was approximately $1 billion, which is funded by the IRS.[209] The net result was that the XEI shareholders, via Wholesale, will have experienced a NRG-related net loss of approximately $2 billion (about a $3 billion loss minus approximately $1 billion in income tax deductions).[210]

152. The NRG losses are reflected on Wholesale's 2003 and 2004 Form 1120's.[211] The remaining unused NRG-based income tax deductions (approximately $500 million) are a deferred tax asset owned by Wholesale.[212] Wholesale is not dependent on the income of NSP-MN to obtain or monetize the value of its unused NRG-based income tax deductions.[213] Wholesale could acquire other profitable businesses and use their income to monetize those unused deductions. XEI anticipates that it will have a significant alternative minimum tax liability for 2006 and that Wholesale's remaining tax deduction will be depleted by 2008.[214]

153. From the outset, the Commission required separation of NRG operations from regulated operations "to prevent ratepayers from subsidizing [NRG] affiliates." [215] This pattern continued in filings seeking Commission approval for NRG-investments in foreign utilities, which were required because NRG was then a subsidiary of the former Northern States Power Company.[216] The purpose was to assure that ratepayers would be no worse off or no better off (i.e., indifferent) with or without any non-regulated activity.[217]

154. The Commission opened an investigation after the onset of the NRG financial difficulties.[218] As part of its Order Requiring Additional Information and Audit in the *Financial Inquiry Docket*, the Commission required further explicit assurances that utility customers would be insulated from the direct and indirect effect of NRG's financial difficulties, including a prohibition on any inter-company loans between NSP-MN and XEI or NRG; an assurance that

NSP-MN would not encumber any Minnesota utility property for the benefit of NRG or other non-utility purposes; an assurance that NSP-MN would not seek rate recovery for costs associated with NRG in a future rate case or through a rate rider; and requirements that NSP-MN take steps to prevent any additional cost of debt or equity in future rate cases.[219] The OAG supported that separation.[220]

155. The Department's thorough analysis in this rate case supported Xcel's conclusion that NSP-MN's cost of debt and equity were not affected by NRG's financial difficulties.[221] The Department further maintains that the rate of return it recommended accounts for any possible impacts from NRG on NSP-MN, and it does not recommend implementing any further adjustment to the proposed income tax expense as recommended by the OAG.

D. Impact of OAG Recommendation

156. The OAG proposal is inconsistent with the principles of separation and matching. It is logically and logistically difficult to use the stand-alone approach to establish a representative test year, then to deviate from that approach for just a single significant item such as income tax expense. It causes a fundamental disconnect with the logic and rationale of the overall process.[222] For example, the treatment of current and deferred income tax expense is based on consistent application of the stand-alone method and leads to substantial reductions in costs (through the deferred tax reduction in rate base).[223] Applying the results of consolidated income tax returns to determine current income taxes, however, undermines the basis for determining deferred taxes that currently serve as an offset to rate base.[224]

157. The OAG has recommended using the results of consolidated tax returns to determine current taxes, and at the same time advocates preserving deferred taxes (which result from the stand-alone method),[225] but offered no explanation for why or how to do both. The OAG's recommendation would lead to an impairment of the company's rate base, because deferred taxes are treated as an offset to rate base on the premise that the company recovered from ratepayers both current and deferred amounts associated with utility investments.[226] As a result, the OAG recommendation would deprive Xcel of recovery of its deferred tax expense (which creates the offset to rate base) that is consistent with current taxes.[227]

158. To be consistent with principles of matching, income tax credits that are specific to the utility would similarly have to be removed from the cost of service calculations to prevent double-counting. Matching would require that disallowed expenses, such as image advertising, lobbying and some long-term incentives, be included in the cost of service, since the deductions from such expenses are included in consolidated income tax returns.[228]

159. Xcel's calculation of income tax expense for NSP-MN is consistent with FAS 109. Xcel uses a separate return methodology that is implemented pursuant to the Tax Allocation Agreement (TAA), to which NSP-MN and all XEI subsidiaries are a party. Contrary to the OAG's assertions, the TAA would not permit attributing the NRG-based tax deductions to reduce NSP-MN's regulated rates. Section 2(b) of the TAA applies to Wholesale's NRG-based tax losses and deductions, and it requires that Wholesale receive the benefit of any tax deduction based on its losses.[229]

160. The OAG's recommendation is based on consolidated tax return results (including prior year results and losses) and $0 income taxes for some years.[230] Such an approach is inconsistent with the financial reporting requirements of FAS 109.

161. The OAG's recommendation is based on the unstated premise that expenses are not real or not legitimate unless they are based on cash expenditures.[231] Regulated costs of service are based on accrued income tax expenses, however, not on cash payments made by XEI to taxing authorities.[232] The fact that cash is not paid to the taxing authorities reflects the application of tax law associated with the loss at Wholesale, and does not mean that NSP-MN has no real tax expense.

162. NSP-MN's financial statements and financial reporting requirements (which require recognition of NSP-MN's income tax obligations based on its own income) would be unchanged if the Commission were to adopt the OAG's recommendation.[233] SEC reporting and the financial markets would continue to recognize the income tax liability of NSP-MN (based on its own income), and neither the SEC nor the financial markets would alter their requirements or their recognition that NSP-MN has an income tax expense as a result of a Commission ratemaking decision.[234]

163. Adoption of the OAG recommendation would likely have an adverse impact on NSP-MN's financial coverage ratios and would likely to lead to a reduction in its bond rates.[235]

164. Adoption of the OAG recommendation would likely have an adverse impact on the credit rating agencies' and financial market's assessment of NSP-MN's regulatory environment, which is a major factor in accessing NSP-MN's business environment and risk.

165. A reduction of NSP-MN's revenues by approximately $100 million would reduce the ROE by approximately 340 basis points (3.4%).[236] Based on the 10.64% ROE recommended by the Department, the resulting ROE would be approximately 7.24% (10.64% - 3.4%). The Department's calculation of ROE appropriately assumed that income tax expense would continue, based on requirements of regulatory accounting and financial reporting and based on investor expectations.[237] An ROE of 7.24% would not be comparable to that

earned by other utilities,[238] and would be far below the ranges of ROE calculated by both Xcel and the Department.[239]

166. The Administrative Law Judge recommends that the Commission reject the adjustment proposed by the OAG. Although the Commission could choose, as a policy matter, to use a method that incorporates an "actual taxes paid" approach, the fair use of such an approach would require adjustments in many different areas, including rate base, operating income, and rate of return. The Administrative Law Judge does not believe it is feasible to achieve such a major change in approach on this record. The adjustment recommended by the OAG —to use a stand-alone test year method and to simply lop off $100 million in expenses—would preclude Xcel from earning a fair return on its investments and ultimately would adversely impact Xcel's ability to provide reliable service to ratepayers.

V. RATE DESIGN

167. Rate design, in contrast to determination of the revenue requirement, is largely a quasi-legislative function. It involves establishment of the utility's rate structure, such as deciding in what proportions the revenue requirement will be recovered from each customer class. This step of rate making largely involves policy decisions.

A. Xcel's Class Cost of Service Study

168. Apportionment of revenue responsibility starts with a Class Cost of Service Study (CCOSS). It should be designed to identify, as accurately as possible, which customer class is responsible for each cost incurred by the utility providing service.[240]

169. Xcel's embedded CCOSS[241] filed with this case uses essentially the same methodology as that approved by the Commission in the 1992 Electric Rate Case,[242] but includes updates and refinements in several areas, including software and format, subclass consolidation, interruptible capacity-cost accounting, energy cost allocation, seasonal split of generation capacity costs, secondary distribution cost allocation, secondary service cost allocation, and general and common plant allocation.[243]

170. Based on the CCOSS, rates would have to increase as follows to achieve the proposed revenue requirement based solely on cost: Residential, 15.3%; Commercial & Industrial (C & I) Non-Demand, 7.3%; C & I Demand, 3.4%; and Lighting, 9.4%.[244]

171. The Department, after obtaining additional information, supports the CCOSS as filed.[245] The Commercial Group also supports the CCOSS as filed.[246]

172. The only three disputed issues related to the embedded CCOSS are: (i) whether to substitute the "E8760" energy cost allocator for the previous "E20" allocator; (ii) whether, in a future electric rate case, Xcel should be required to apply a "break-even point" analysis to its currently approved method for "stratification" of fixed production costs; and (iii) whether, in a future electric rate case, Xcel should be required to maintain the status quo on subclass information.

1. The E8760 Allocator

173. The energy allocator used in past CCOSS studies (the E20 allocator) is based on the system on- and off-peak marginal energy cost ratio applied to the class on- and off-peak use percentages. It was calculated using the type of time-variant data then available, which was a two-period costing method.[247] Xcel now has available cost and load data and software making it practical to develop a more refined variant of this allocation technique, which makes use of all 8,760 hours of the year to replace the two-period method (the E8760 allocator).[248]

174. The Department supports the use of the E8760 allocator in the CCOSS.[249]

175. The OAG and ECC opposed the E8760 allocator on the basis that it essentially constitutes a "time-of-use" rate for fuel costs of residential customers.[250]

176. Use of the E8760 allocator does not change rate design from standard rates to time-of-use. The allocator is used to assign class cost responsibility in the CCOSS. The change to the E8760 allocator shifts a small additional portion of the total "energy-related" cost to the residential and the non-demand C & I classes, as reflected in the filed CCOSS.[251]

177. There is no substantiated claim that the E8760 allocator does not produce accurate results. What the OAG seems to be objecting to is that the allocator makes the assignment of costs to customer classes more accurate, and it contends that this will adversely impact residential customers because they can do little to change their time of energy use. The Administrative Law Judge recommends that the Commission approve use of the E8760 allocator as a refinement in the method used to allocate costs. It is important that the cost allocations be as accurate as possible so that other adjustments made in the rate design process—that are not based on cost—still send accurate price signals to consumers.

2. Break-Even Point Analysis

178. Xcel used the stratification method, approved by the Commission in prior rate cases, to allocate production plant between energy-related and demand-related costs.

179. The Large Industrial Group contends that the stratification method is biased against high load factor industrial customers and that all fixed production costs should be allocated on the basis of demand where the demand measure is derived from the peak period of the system. It requested that Xcel be required to include a "break-even point analysis" in the CCOSS it files with the next electric rate case to establish the portion of production plant that is energy-related and demand-related.[252] According to the Large Industrials, under a break-even methodology, about 25% of the fixed costs of a baseload plant would be treated as energy-related, and the remaining 75% would be treated as capacity-related, to be recovered on the basis of relative class contribution to system peak load.[253] That means that 75% of the fixed cost of a baseload plant, which has historically been treated as an energy-related cost, would be treated as a capacity cost in the same manner as the cost of a peaking plant.

180. The Chamber of Commerce supports the break-even point proposal, but suggests incorporating an additional break-even analysis with respect to intermediate generating plants.[254]

181. The break-even methodology would shift responsibility for the higher fixed production costs of baseload plants to customers who have proportionately higher peak loads relative to total energy use, with the likely outcome of shifting costs to residential and small commercial customers.[255] This method would likely allocate an additional 0.75% to the residential class, an additional 1.18 % to the C & I Secondary Class, and 3.0 % less to the C & I Primary Class.[256]

182. Xcel and the Department oppose the proposition that all fixed production costs should be allocated on the basis of demand because there are significant differences in the fixed costs of peaking vs. baseload plants, and the proposed allocation method fails to take into account that the higher capital costs of a baseload plant are incurred in order to obtain lower energy cost.[257] The Department does not support the proposed requirement of a break-even point analysis in future studies because there is insufficient detail to determine how such an analysis would be performed and applied to the allocation of all fixed production costs.[258]

183. Xcel also maintains that this method is the same as the "fixed-variable" method rejected by the Commission in NSP's 1991 electric rate case.[259] There, the Commission supported the use of Xcel's stratification methodology, which has been used since that time.

184. The Large Industrial Group has failed to show that a break-even point analysis, as it is described in the testimony, would more accurately determine the cost of serving the respective classes. The Administrative Law Judge recommends that the Commission reject this proposed requirement for the next CCOSS.

3. C & I Subclass Information

185. Historically, Xcel has had multiple commercial and industrial classes with different rates for firm and interruptible service and various discounts based on delivery voltage levels. In the CCOSS Xcel combined those subclasses into a single C & I Demand Class. That consolidation did not include a consolidation of rates, and the CCOSS continued to provide cost information for the various rate categories. The Large Industrial Group requests that Xcel be "required to continue to maintain this information" in order to permit rates to be based on cost.

186. Xcel opposes this request, arguing that it should be permitted to design its CCOSS in a manner that supports the rate categories it deems appropriate.

187. The Administrative Law Judge recommends that the Commission require Xcel to continue to provide cost information for existing rate categories in its next CCOSS so that other parties can determine whether combining subclasses results in a fair allocation of cost.

4. Marginal Cost Study

188. In compliance with the Commission's Order in the 1992 Electric Rate Case, Xcel provided an alternative marginal cost study in this proceeding.[260] Xcel did not apply the results of this particular marginal cost study in developing its rate design proposals for this rate case.[261] The Department reviewed the marginal cost study and agreed that Xcel had satisfied this compliance filing requirement.[262]

B. Revenue Allocation to Classes

189. The issue of how to allocate the revenue responsibility between the various classes (as distinguished from cost responsibility discussed above) has two subparts: how to perform the initial allocation based on Xcel's proposed revenue requirement, and how to adjust that allocation to reflect the final revenue requirement as determined by the Commission.

1. Initial Allocation

190. Xcel proposed a revenue allocation to the various classes based on a combination of cost and rate stability factors. Xcel proposed that revenue responsibility be allocated as follows: Residential, 10.9%; C & I Non-Demand, 10.1%; C & I Demand, 6.1%; and Lighting, 9.2%.[263]

191. The Department agreed, except for Xcel's initial proposal to terminate the Municipal Class, and the Commercial Group agreed with Xcel's proposed allocation of the initial revenue requirement. [264] The Department's

proposed initial allocation is as follows: Residential, 10.9%; C & I Non-Demand, 10.1%; C & I Demand, 6.1%; Municipal, 7.4%; and Lighting, 9.2%.[265]

192. The Large Industrials largely agreed with Xcel's proposed allocation, but suggested that the increase to the C & I Demand Primary class be capped at 3%, with the residual being spread to the Residential and C & I Large Demand Secondary classes.[266] The Commercial Group opposed the suggestion of a higher increase for the C & I Demand Secondary class, because that group does not have a stand-alone rate; thus, targeting an increase for this group would necessitate raising rates for a significantly larger group of C & I Demand customers, many of whom already pay rates above cost.[267]

193. The Chamber of Commerce proposed that the revenue requirement be apportioned to match the costs exactly as set forth in the CCOSS.[268] This would mean increases as follows for each class: Residential, 15.3%; C & I Non-Demand, 7.3%; C & I Demand, 3.4%; and Lighting, 9.4%.

194. The OAG proposes a uniform increase for all customer classes.[269] For example, if the total revenue requirement is an 8% increase, each customer class would be increased 8%. The ECC agreed with this proposal.

195. The Chamber's proposal to base rates solely on cost fails to give any consideration to non-cost factors, such as ability to pay, and would clearly result in rate shock for the Residential class. The OAG's proposal to apply an increase uniformly across classes disregards the relative cost responsibilities of each class and would fail to maintain the relationship of rates to costs established in the 1992 Electric Rate Case. The record reflects that apportioning a 10.9% increase to the Residential class would give that class an amount of financial support from other customer classes that would be approximately equal to the support approved by the Commission in the 1992 Electric Rate Case.[270]

196. Xcel's initial proposal for class revenue responsibility, as supported by the Department with the inclusion of the Municipal class, is a reasonable starting point for determining the revenue allocation of the Commission-approved final revenue requirement.

2. Allocation of a Revenue Reduction

197. If the final revenue requirement approved by the Commission is lower than the one proposed by Xcel, it will be necessary to adjust the proposed revenue allocation to reflect the final revenue requirement. Xcel, the Commercial Group, and the Large Industrial Group propose using a lower revenue requirement as an opportunity to move subsidized classes closer to cost (in percentage terms). In other words, they propose reducing each class increase by the difference between the overall percentage requested and the overall percentage increase determined by the Commission. For example, if the Commission were to approve a 5% increase in the revenue requirement, as

opposed to the 8% sought by Xcel, the revenue allocation for each class would be reduced by 3%. Thus, the responsibility of the Residential class for the increase would be 7.9%; C & I Non-Demand, 7.1%; C & I Demand, 3.1%; Municipal, 4.4%; and Lighting, 6.2%.[271]

198. The Department proposes using the same ratio of class revenue requirements as proposed for the initial allocation to determine class revenue responsibility for any reduced revenue requirement. It converted the percentage increases for each class to a percentage reflecting the proportion of the unadjusted revenue for each class compared to the total revenue requirement. Thus, the Residential class would be responsible for 36.6% of the revenue requirement, whatever that number might be; the C & I Non-Demand Class, 4.0%; C & I Demand, 58.1%; Municipal, 0.3%; and Lighting, 1.1%.[272]

199. The difference between Xcel's proposed allocation of a reduced revenue requirement and that proposed by the Department is relatively small; however, the Administrative Law Judge recommends using the Department's proposed method because it maintains the relationship of rates to costs established in the 1992 Electric Rate Case and would result in a slightly smaller percentage of the revenue requirement being assigned to the residential class. Given the rapidly increasing energy costs that all customers have and will continue to face, and the inability to pay of many low income residential customers, there should be no further movement toward cost for the residential class at this time.

C. Fuel Clause Rider Tariff

200. The Fuel Clause Rider (FCR) mechanism currently has two steps. First, the fuel and purchased power costs in the test year are recovered in base rates through the energy charge of each tariff that is approved by the Commission in a rate case. Second, fuel costs above the amount set in base rates are allocated monthly to classes on a direct kWh-use basis through the fuel clause adjustment (FCA) filings.[273]

201. Xcel made a variety of proposals to change the FCR mechanism, which evolved over the course of the hearing. In its Initial Brief, Xcel proposed the following changes: reporting a single combined fuel cost on customer bills; unbundling the base cost of fuel from the non-fuel energy charge; using the E8760 allocator to allocate the monthly FCA adjustments to the various customer classes, as opposed to allocating on a kWh-use basis; identifying the class base fuel and purchased energy costs in the FCR tariff; providing the amount by which current fuel costs vary from the base amount in its FCA filings, consistent with the manner such information is currently provided; and developing a new base cost of fuel for each customer class in future rate cases and, as it did in this case, calculating the percentage impact of any proposed increase from present rates, which would include fuel costs.[274]

202. The Department does not oppose the proposal to show fuel costs as a one-line item on a customer bill, which is what the Department proposed and the Commission ordered in another docket.[275]

203. There appears to be some confusion in the record as to what it means to "unbundle the base cost of fuel from the non-fuel energy charge." As the Administrative Law Judge understands this issue, Xcel is now proposing to remove fuel costs from the base rates *shown on the customer's bill*, to avoid having the base cost of fuel reflected in both base rates and total fuel cost and thus cause confusion for customers, as they would not be able to add up the various charges and have it equal the total bill.[276]

204. The Department does not appear to oppose this change on the customer bill, as long as Xcel continues to use a two-step process in its FCR tariff to (1) identify the class base fuel and purchased energy costs, and (2) provide the amount by which current fuel costs vary from that base amount in its FCA filings, consistent with the way in which this information is currently provided. If this understanding is correct, the Administrative Law Judge does not believe there is a dispute between Xcel and the Department. If the Commission desires to have total fuel costs displayed as a separate line item on the bill, then it could permit Xcel to exclude the base cost of fuel from the energy charge shown on the bill to prevent customer confusion, without any change to the tariff mechanism.

205. The Department is opposed to removing fuel costs from base rates in this proceeding and moving to a one-part FCR design in which all fuel costs flow through the monthly FCA. The Department is concerned that taking all fuel costs out of base rates would affect the Commission's opportunity to allocate revenue responsibility for some of this expense among customer classes based on factors other than cost. Xcel's proposal addresses this concern to some extent, in that it would continue to identify the class base fuel and purchased energy costs in the FCR tariff and further identify the amount by which current fuel costs vary from the base amount in its FCA filings, which would preserve this data for purposes of making rates. It is difficult to identify exactly how these proposals differ and what the impacts might be on rates. If there is in fact a dispute between the parties as to how the FCR process would work, as opposed to how fuel costs would be reflected on the customer's bill, then the Administrative Law Judge recommends that the issue be considered in the Commission's pending FCA docket,[277] as opposed to this rate case.

206. In the CCOSS, Xcel proposed to use the E8760 allocator, instead of the E20 allocator, to recover the base cost of energy in base rates. It proposes that the E8760 allocator also be used to allocate the remaining fuel costs to classes through the monthly FCA. Although Xcel initially proposed that the E8760 allocator be updated annually, it has now agreed not to do so between rate cases. The Department agrees with the modified proposal to use the E8760 allocator in the FCA, with no changes between rate cases.[278]

207. The OAG and ECC object to use of the E8760 allocator in the fuel clause tariff, for the same reasons they object to using it in the CCOSS. They contend that it is similar to a time-of-use rate and is unfair to the residential class, which is unable to shift its use to the off-peak period.

208. Use of the E8760 allocator does not establish a rate. It simply assigns costs more accurately to customer classes. The Administrative Law Judge recommends that the Commission accept the use of the E8760 allocator as described above.

209. Xcel proposed several changes to the WindSource rider, including changes related to its one-step FCR proposal, some language changes, a small increase in the WindSource charge, and a request to recover the avoided-capacity cost credit built into the WindSource rate through an increase in base rates. The Department supports all of the proposed changes except for those related to the one-step FCR proposal.[279]

1. Use of Marginal Cost in the Time-of-Day FCR

210. Xcel uses marginal cost information as an input to determine the energy cost allocator, which is then applied to the actual average embedded costs of energy. Xcel has used this marginal costing technique for allocating fuel and other energy-related costs for many decades.[280]

211. The Chamber of Commerce argues that average cost rather than marginal cost should be used in determining the time-of-day (TOD) differentiated FCR —asserting that using marginal cost penalizes on-peak customers, because the actual fuel costs recovered in rates are lower average costs.[281] Use of the Chamber's proposal would mean that on-peak FCA would be 38% greater than the off-peak FCA—compared to Xcel's proposal, which results in an on-peak FCA that is 67% greater than the off-peak FCA.[282]

212. Marginal costs identify more accurately the incremental cost of use at peak. Xcel asserts that it is appropriate to use marginal cost in a TOD setting, in which the primary purpose is to send price signals to customers to shift use to lower cost off-peak periods. If the Chamber's proposal were adopted, it would lower the cost of on-peak fuel charges, thereby reducing the TOD customer's incentive to control its demand during peak periods.

213. The Chamber also argues that its proposal to use average fuel cost rather than marginal fuel costs in the TOD fuel clause rate is needed to soften the rate impact of moving to mandatory TOD energy charges.[283] The mandatory TOD rates will only apply to customers with more than 1000 kW of demand. All of those customers are in the C & I Demand class. Under all rate design proposals (except the OAG's), this class will receive the smallest percentage

increase. Furthermore, the Department has recommended a nine-month phase-in period for mandatory TOD energy charges (see discussion below).

214. Xcel's use of marginal cost information is reasonable, and it provides the appropriate incentive to reward use of off-peak energy. The Administrative Law Judge recommends that there be no change in the use of marginal cost information. The Chamber's concerns regarding "softening" the rate impact of mandatory TOD rates for the C & I Demand class can be addressed as recommended by the Department, if the Commission deems it necessary.

2. FCR Tariff Language

215. During the course of the proceeding, Xcel and the Department reached agreement on the specific language to include in the FCR tariff.[284] The tariff language would have to be further modified if the Commission approves the Settlement on Wholesale Margins, and Xcel has committed to work with other parties to assure that its revised compliance filing FCR tariff accurately incorporates the terms of the Wholesale Margins settlement.

3. Variance

216. Because of the changes Xcel has made in its proposals concerning the FCR/FCA, it is not clear whether it still needs a variance from certain Commission rules related to its FCA proposal.[285] The Department maintains that if the Commission were to approve the proposed FCA in a rate case, there would be no need for a variance. If that is not correct, the variance language could be reviewed in a compliance filing.

D. Dual Feeder Service

217. A small number of Xcel's business customers (about 160 out of 128,000) have very high reliability requirements.[286] One way these customers can reduce the risk of extended outages is to have Xcel install a second distribution feeder path. This second feeder duplicates the standard feeder and runs from the substation to the customer's premises. If a storm or other event damages the first feeder, a switch at the customer's premises transfers the customer's service to the second feeder. Xcel calls this Dual Feeder (DF) service.

218. When a customer asks for DF service, Xcel either builds new feeder facilities and/or reserves existing feeder facilities so that the customer has a second dedicated backup feeder. If there is any part of the distribution system that does not have adequate capacity to provide such service without

jeopardizing reliability for other customers, new distribution facilities are constructed. In the DF tariff, this immediate construction of new facilities is called "alternate feeder construction." Under some circumstances, alternate feeder construction could extend all the way back to the substation. In such a case, there would be no charge for "reserved feeder capacity," because there would be no use of existing facilities.[287]

219. In most cases, it is not necessary for the alternate feeder construction to extend all the way to the substation because there is usually adequate capacity in at least some portions of the upstream system to complete the DF service by means of "reserved feeder capacity." This means the DF service is usually provided partly by alternate feeder construction (near the customer's service point) and partly by reserved feeder capacity (on the upstream end of the system). Because the reserved feeder capacity, up to this point, has been part of the normal distribution planning reserves, this capacity must be replaced quickly (usually within one year) to restore distribution system planning reserves.[288]

220. Xcel is not proposing any change to the physical characteristics or the terms and conditions of the existing DF service. Xcel is proposing instead to change the rates. In the past, Xcel has charged only for the upfront cost of the switchgear and upfront cost of any alternate feeder construction. It is proposing changes in the rates to apply to *new* DF customers that would recover upfront construction costs for reserved feeder capacity and on-going operating costs for switchgear, alternate feeder construction, and reserved feeder capacity.

221. The Department characterizes Xcel's proposal as being nearly identical to a proposal that was previously rejected by the Commission.[289] When Xcel proposed similar new charges for DF service in a miscellaneous filing (Docket E-002/M-05-113), the Commission rejected the petition but encouraged Xcel to address this issue in this rate case.[290]

222. There are two basic disputes associated with Xcel's proposal. The first is a concern that there could be "double recovery" with regard to the charge for reserved feeder capacity, and the second is a dispute over whether the ongoing charge should include indirect costs.

223. The Department maintains that because Xcel intends to charge an upfront fee for facilities that already exist in rate base, it would double-recover these costs from the new DF customer. Xcel maintains that there is no double recovery because the "reserved feeder capacity" charge is actually a charge for building replacement facilities at some point in the future. But because the facilities are to be built in the future, the cost is modified by a time-value of money adjustment to reflect the delay in construction.

224. The Administrative Law Judge agrees with Xcel that the reserved feeder capacity charge is similar to the alternate feeder charge, in that the new

customer is actually paying the cost of new feeder facilities but on a delayed basis. Although the specific facilities dedicated to the customer existed previously in rate base, those facilities are no longer available to all customers as part of the distribution planning reserves and must be replaced. There is no double recovery in terms of the upfront charge, and there is nothing inappropriate about charging the new customer the cost of replacing feeder facilities that are no longer available to other ratepayers. In fact, if no charge is made to the DF customer for replacing this capacity, then all customers will end up paying for this investment in distribution facilities in future rates.

225. It appears that the Department's concern over the reserved feeder capacity charge would be eliminated if the reserved feeder capacity charge were not implemented until after any replacement feeder were actually constructed. That, however, would delay the service for up to a year. Xcel asserts that such a delay is not necessary because the proposed rate reflects the time-value of money, reducing the charge to the DF customer to acknowledge that there will be a delay in replacing the reserved feeder. Second, Xcel will remove the reserved feeder from rate base until it is replaced. For example, during 2007, Xcel expects that two new dual feeders will be added. Under Xcel's proposal, payments for reserve feeder capacity will be credited to the plant account (reducing rate base) and then a year or so later, when the replacement feeder is built, the plant account will increase back up to where it was before the DF service was implemented.

226. The Chamber does not oppose the proposed construction charge for replacing reserved feeder, as long as the redundant feeder is not otherwise constructed for area load growth and reliability reasons and is exclusively and wholly dedicated at all times to a single customer's redundant use, extending all the way from the bulk distribution substation directly to the customer's site; and as long as the charges would not apply if the customer is paying for feeder construction cost and redundant feeder is not carrying the load.[291] Xcel asserts that its proposal satisfies these conditions (subject to its caveat that "bulk distribution substation" means the substation used to serve the customer).

227. The only concern raised by the Large Industrial Group is that the DF rate should not apply where the customer needs additional facilities simply to receive standard service.[292] Xcel agrees that no additional charge would be made for the provision of standard service.[293]

228. Based on Xcel's estimate that two customers might request DF service in 2006, the Department further argues that Xcel's proposal should have resulted in a test-year adjustment to rate base and operating revenues.[294] This is not a known cost, because to date no new Dual Feeders have been added. These costs are not part of the 2006 budget because the requests are limited and sporadic, and thus there is not a representative level of revenues and rate base offsets that should be reflected in this proceeding. Even if there had been ongoing projects every year, a representative level of revenues would simply

have served to offset increased investment expense associated with the Dual Feeder projects included in the test year, resulting in no change in the revenue requirement.

229. Also at issue in this dispute is whether DF ongoing costs should be limited to the variable cost of service (i.e. direct cost—the Department's proposal) or whether the rate should be based on a fully-allocated cost (i.e. include both direct and indirect costs—Xcel's proposal). The Department's lower proposed ongoing cost was determined by eliminating 10 of the A&G expense categories (i.e. salaries, employee benefits, office supplies, etc.) that Xcel included in its proposal.[295]

230. While these A&G costs are indirect, they are currently applied to all distribution facilities. In addition, while the costs are indirect, they are incremental to the provision of DF service, just as they are for all other distribution plant facilities.[296] Xcel's position is that, as a matter of inter-customer fairness, DF customers, who voluntarily take this premium service, should pay the same contribution toward cost for their DF facilities as other customers pay for use of non-dedicated feeder facilities.

231. The Department argues that Xcel has not shown that DF customers have higher O&M costs per kWh than other customers.[297] In fact, DF customers have access to both the existing feeder and the dedicated DF facilities. It is the access to dual facilities (one of which is for the DF customer's dedicated use) that justifies the additional O&M charge.

232. It is not improper for Xcel to charge its overhead costs on new facilities. Charging a customer a DF rate that includes the overhead loadings is no different than charging new customers in a new service area (e.g. in a new residential development) the same rate that is charged to existing customers.

233. The Department asserts that Xcel appears to be expanding and replacing its distribution facilities using DF customers to finance that expansion.[298] The only expansion that DF customers are financing, however, is the expansion necessary to provide the DF service they requested.

234. Finally, the Department raised a concern that service reliability could be affected.[299] No change in the nature of the service is proposed, however, and the service has not resulted in service reliability issues in the past. Furthermore, where existing facilities are not adequate to provide reliable service, Xcel will construct alternate feeder. The alternate feeder upfront charge is nothing new.[300]

235. Xcel's proposal is reasonable in that it assures that the few DF customers who benefit from it pay the costs of this service. Xcel's proposal appropriately addresses concerns of all customers and reasonably assesses the appropriate ratepayers for costs incurred for the service.

E. Interruptible Load Tariffs

236. Xcel filed its interruptible rate schedules, which set forth the rate discounts it provides to customers who agree to allow the interruption of load during periods of peak use.

237. Xcel did not seek to change the current level of control demand discounts for interruptible customers.[301] Instead, Xcel filed interruptible rate schedules to comply with prior Commission orders, update and clarify tariff language, eliminate certain riders that limit the number of customers who can benefit from interruptible rate discounts, and create additional customer groups with smaller blocks of interruptible load to avoid interruptions that go beyond the necessary load relief. Xcel also proposed a $60 per MWh threshold for determining when it may call an energy control period (meaning Xcel could interrupt load when its estimated cost of production or purchases exceed $60 per MWh).

238. The Department supported all the proposed tariff changes related to Xcel's interruptible rate tariffs and did not recommend any further changes or additions.[302]

239. The Large Industrial Group proposed two changes to Xcel's interruptible rate tariffs: (i) increasing the proposed interruption threshold from $60 per MWh to $70 per MWh related to the Company's Tier 1 Energy Controlled Service Rider; and (ii) increasing the capacity credit to customers under the Tier 1 Peak Controlled Schedule L Interruption Rider customers by $1.23 per kW.[303]

240. In response to the Large Industrial Group's concerns, Xcel agreed to raise the threshold from $60 to $70, subject to re-evaluation in the next rate case.[304] Xcel also agreed to a $0.50 increase in the capacity credit for schedule L customers, and the Large Industrial Group agreed to this increase as reasonable in lieu of its proposed $1.23 increase.[305]

241. The $0.50 increase is based on the reasonable premise that Schedule L customers provide interruption performance beyond that provided by other interruptible customers, because Schedule L customers agree to be interrupted with only a 10-minute notice. As such there is greater value from Schedule L customers, and the additional discount is similar to that proposed by Xcel.

242. The Chamber has accepted both the increase in the interruption threshold to $70 and the $0.50 increase in the capacity credit for Schedule L customers, consistent with the agreement between Xcel and the Large Industrial Group.[306] The Chamber argued, however, for a higher interruptible load credit for all customers, not only those under Schedule L, based on its contention that the current rate discounts fail to reflect the benefits of load interruption on transmission congestion.

243. Xcel maintains that the short-term interruption of load during peak use under the interruptible load tariffs addresses generation reserve needs, not transmission congestion.[307] Because Xcel is not able to defer or avoid any transmission facilities, it maintains there is no value meriting a further discount to interruptible customers.[308] According to Xcel, transmission congestion may actually occur more frequently in off-peak periods.[309] The Large Industrial Group agrees that the benefits of interruptible load are reduced energy and capacity costs, not reduced or avoided transmission costs.[310]

244. The Commission has considered this question previously and declined to accept the argument at the time that payments for interruptible customers should include a component to reflect some value of avoided transmission costs.[311]

245. There is no persuasive evidence on the record in this proceeding that would compel requiring an increase in interruptible rate discounts based on transmission savings. Specifically, the record fails to establish any nexus between the interruption of peak load and transmission congestion that would merit a further discount. Nor has the Chamber quantified the value of the additional proposed discount or provided a record that would permit the Commission to determine the effect of applying such a discount on other classes of customers. Accordingly, Xcel's proposed interruptible tariffs, including the higher threshold and discount for Schedule L customers as agreed to by the Large Industrial Group, are reasonable and should be approved.

F. Marginal vs. Average Cost for WindSource Credit

246. Xcel determined the fuel clause rider credit for WindSource based on average cost, as directed by the Commission in Docket No. E002/M-01-1479. In that docket, the Commission prescribed the methodology to be used in setting the WindSource rate.

247. The Chamber contended that the fuel clause rider credit applied to the WindSource rate should be based on marginal rather than average fuel cost. The Chamber's proposal would increase the amount of credit given to the WindSource rate.[312]

248. Xcel asserts that the Commission should not reconsider one element of its prescribed methodology without reconsidering other elements.[313] Xcel makes annual filings regarding its WindSource rate and asserts that any comprehensive review of that rate should take place in those proceedings.

249. The Commission's decision to use average rather than marginal cost to determine the WindSource discount was reasonable, and any changes to that methodology would not be appropriate as part of this proceeding.

G. Rules and Regulations

1. Amount of Contribution in Aid of Construction for Service Extensions

250. Historically, Xcel charged customers a Contribution in Aid of Construction (CIAC) for service extensions when the cost of the extension exceeded three times the customer's anticipated annual revenues. For purposes of administrative efficiency, Xcel included fuel cost-related revenues in making the calculation, even though fuel costs are not directly related to the capital/rate base-related costs of providing utility service.

251. The inclusion of fuel cost revenues did not cause a problem in the past because they were relatively small and stable; however, significant increases in recent fuel costs have caused Xcel to change the formula for calculating the CIAC charge. Xcel has proposed to modify the tariff to read "three times the customer's anticipated annual revenues, <u>excluding the portion of the revenue representing fuel cost recovery</u>."[314] This change would be applied to both Residential and nonresidential customers.[315] Without this change, all ratepayers, as opposed to the ratepayers requesting the service extension, would pay significantly larger amounts of special investment simply because of fuel cost escalation.[316]

252. The Chamber opposed Xcel's change because it would increase the amount of CIAC charged compared to historic practices. The Chamber proposed that fuel costs of 1.354 cents per kWh be included for C & I ratepayers when applying the formula. The 1.354 cents per kWh is equivalent to the fuel costs included in the prior formula in 2005.[317]

253. In response, Xcel proposed increasing the formula to 3.5 times revenue (excluding the fuel cost-related revenues), which is essentially equivalent to 3.0 times-revenues (including the 1.354 per kWh fuel costs) for residential customers.[318] Xcel provided an analysis demonstrating that its 3.5 times revenue formula yields essentially the same construction allowance as the Chamber's proposal, at test year 2006 rates, and also shows that these methodologies yield the same construction allowance for residential customers as was present in 1993 rates. [319] For C & I customers, the formula would have to be 3.94 times revenues to yield the same allowance as in 1993.[320]

254. Xcel has never had, and does not recommend establishing, a separate higher "revenue" factor for General Service customers. Instead, Xcel has proposed a uniform amount of allowable investment for all customer classes. The Chamber's proposal is premised on different customer classes being allowed different levels of investment without incurring a CIAC. Xcel favors a uniform formula for determining the amount of CIAC.

255. If Xcel were to differentiate the formula based on customer class, it would not be unreasonable to charge C & I customers more than Residential customers. The Chamber has failed to demonstrate why the 3.5 times revenue proposal would be unjust or unreasonable to C & I customers. Xcel's formula for determining the CIAC charge is reasonable and supported by the record.

2. Form of Payment for CIACs

256. Section 5.2 of Xcel's tariff allows it to determine the manner of payment for CIACs. The alternatives include a single up-front payment (the usual case), a periodic payment plan, or some combination of the two. The Chamber proposed that the customer be allowed to select the alternative or, in the alternative, that the rules be revised to specify when each type of payment will be applied.[321]

257. Xcel disagrees with this proposal. It maintains that it needs the discretion to determine the manner of payments for CIACs, because issues related to credit quality and responsible parties are not easily addressed through fixed standards.

258. The record does not suggest that Xcel has been arbitrary or unreasonable in selecting payment alternatives or that its selection of an alternative has caused problems for any customer. The record does not support the conclusion that the current practice has resulted in systemic problems that compel a change. In the absence of such evidence, Xcel's proposal to retain the flexibility to select a payment alternative continues to be reasonable.[322]

H. Settled Rate Design Issues

1. Residential Customer Charge

259. Xcel initially proposed a residential customer charge of $7.09 to more closely reflect the cost of service.[323] In later testimony, Xcel proposed a modified customer charge of $6.50, which was the customer charge recommended by the Department. The OAG proposed a $6.00 residential charge, while the ECC proposed a $5.00 customer charge.[324]

260. After discussions with all affected parties, Xcel entered into a settlement agreement with the ECC. Pursuant to that settlement, which the OAG supports, Xcel agreed to a residential overhead customer charge of $6.00.[325] The settlement agreement further provides that customer charges for residential overhead space heating, residential underground, and residential overhead time-of-day would be $8.00, while the customer charge for residential underground time-of-day space heating would be $12.00.[326] As part of this settlement Xcel agreed to cooperate with the ECC on a low-income consumption study, recognizing limitations on its ability to share customer-specific data.[327] Also, as part of this settlement, the ECC agreed to withdraw its proposal for an inverted

block or lifeline rate, thus resolving the dispute in this proceeding related to the impact of the customer charge on low income customers.[328]

261. No party opposes the residential customer charge settlement.[329] The settlement will provide residential customers with a significantly lower customer charge than the one initially proposed by Xcel. It will also help facilitate the development of a better understanding of low-income energy consumption, which may ultimately provide Xcel and the Commission with a better understanding of how to best protect the interests of low-income ratepayers. As such, the settlement reflects a reasonable compromise that is in the public interest.

2. Low Income Discount

262. The Department proposed raising Xcel's credit to low income customers under Minn. Stat. § 216B.16, subd. 4, by $.0064 per kilowatt hour in conjunction with raising the residential customer charge to $6.50.[330]

263. Subsequent to the Department's recommendation for an increase in the low income credit, Xcel agreed to a lower residential customer charge of $6.00. The Department's proposed increase in the credit was tied specifically to its proposed $6.50 residential customer charge, not the currently proposed and unopposed monthly charge of $6.00.[331] Therefore, the dispute regarding the Department's low income discount proposal appears to be resolved for purposes of this proceeding.

I. Rate Design Issues Resolved Through Testimony

1. Real Time Pricing

264. The Department sought more information from the company on whether the benefits of the real time pricing program (RTP) outweigh the costs. Xcel indicated that, because only three customers have participated in the program since January 1, 2005, Xcel is not in a position to provide a meaningful evaluation of the RTP. Therefore, Xcel proposed filing the report requested by the Department in the Spring of 2008 after three years of participation to facilitate a more meaningful analysis.

265. The Department supports the company's proposal, and no other party opposes it.[332] The proposal is reasonable.

2. Mandatory TOD Tariff

266. Xcel proposed a mandatory time-of-day tariff for customers who use at least 1,000 kW of electricity. The Department recommended approval of the tariff, but with a modification that would include a nine-month implementation delay.[333] Xcel maintained that no delay was necessary given that customers have been on notice since November 2005 that time of day rates would be

required for all customers who meet or exceed the 1,000 kW;[334] however, Xcel would not oppose an additional nine-month delay if it were the final recommendation.[335] No party opposes the mandatory TOD tariff proposed by Xcel. If the Commission deems it necessary, Xcel would agree to include the nine-month delay recommended by the Department.

3. Municipal Pumping

267. Xcel initially proposed eliminating its municipal pumping rate tariffs and placing those customers on alternative rate schedules. That proposal was initially opposed by witnesses for the Department, SPRWS and SRA. Based on this opposition, Xcel agreed in Rebuttal Testimony to retain the municipal pumping rates.[336]

268. Xcel and the SRA also agreed that, with respect to the Demand Metered Class, the exclusion from the demand ratchet will be retained and the equivalent general service rates approved in this proceeding will apply. Xcel also proposed to reduce the existing discounts for the small municipal class from the general service rate to half of what they are now instead of fully eliminating them and to work with the parties on developing different rate structures for the next general rate filing to address concerns related to municipal pumping.[337]

269. The Department, SPRWS and SRA have accepted Xcel's modifications related to municipal pumping as reasonable, and no other party opposes the modified proposal.[338] The modified proposal is reasonable.

4. Standby/Supplemental Service Rider

270. The Chamber filed testimony arguing for the elimination of the potential capacity charges under Section 10 of the Standby/Supplemental Service tariff. [339] Xcel agreed to offer an additional tariff option that waives the application of this potential charge provision to the extent a customer obtains appropriate accreditation from the Midwest Reliability Organization (MRO) and MAPP.[340] The Chamber agreed to this condition for waiving the potential charges.[341] Therefore, this issue has been resolved.

5. Aggregation/Coincident Peak Billing

271. The SPRWS and SRA recommended that the Commission order a study exploring the development of an aggregation rate following the conclusion of this rate case.[342] The Chamber advocated requiring that an aggregation rate, referred to as coincident peak billing, be established immediately in this proceeding for a business or institution served at more than one service point on a contiguous property.[343] Xcel agreed to work with the SPRWS, SRA and the Chamber on the design of tariffs that address the aggregation issue.[344] Xcel's commitment to work with parties to address this issue, given that no specific rate proposals were offered in this proceeding, is reasonable, and should resolve all disputes related to this matter.

6. Voltage Discounts

272. Xcel contended that, based on the CCOSS, the demand charge discounts should be reduced slightly from present levels and the energy charge discounts increased slightly.[345] Accordingly, Xcel proposed reducing the demand charge discounts by $0.05 for primary service, $0.10 for transmission transformed service and $0.15 for transmission service.[346] These reductions are about half of the amount of the reduction indicated by the TY 2006 CCOSS, and Xcel's proposed energy charge discounts are at the new, indicated cost level.[347] No party has filed testimony opposing these voltage discount proposals. The voltage discounts are supported by the CCOSS and are reasonable.

7. CIP Rider

273. Xcel proposed an increase of $43,040,755 in the level of the Conservation Cost Recovery Charge (CCRC) included in base rates to reflect 2006 test year costs.[348] The change equals the sum of the approved 2006 budget plus the approved EnSave Project cost. The Department supports this proposed CCRC level as well as Xcel's proposed calculation method, with the caveat, accepted by Xcel, that calculation of the final CCRC should be deferred until the final forecast of Minnesota sales is approved by the Commission in this proceeding.[349] No party opposes Xcel's proposal, which is reasonable in that it reflects approved costs and budgets related to CIP.

8. Rules and Regulations

a. City Requested Underground Facilities

274. The Department initially proposed changes in how Xcel recovers its costs for underground facilities installed at the request of a City. After reviewing Xcel's explanation of its practices,[350] the Department withdrew its proposal to change the existing practice.[351]

b. Service Processing Charge

275. Xcel had proposed to reduce from $10.00 to $5.00 the Service Processing Charge to make it consistent with the recently approved service charge approved in the 2004 Natural Gas Rate Case. The Department recommended a $7.00 rate, which is higher than the comparable charge in its Minnesota Gas tariff but closer to the current cost level.[352] Xcel accepted the Department's proposal as reasonable, and the reduction to $7.00 is consistent with Commission precedent and with the current cost of service.

c. Limitation on Using an Income Tax Gross-Up Factor

276. Xcel accepted the Chamber's proposal that it not apply an income tax gross-up to CIACs for service extensions and for special facilities.[353] This

approach is consistent with current practices as long as sales of property are excluded. Xcel will include the appropriate tariff language in its compliance filing.

9. Filing and Reporting Requirements

277. The Department proposed four filing requirements.[354] Xcel responded as follows to those requests:[355]

a. Xcel Energy will file a report on additional improvements on CRS billing system data within one year of a final Commission order in this proceeding.

b. Absent a change in current rules, a utility should not be required to provide data used in test year sales forecasts to the Department sixty days prior to filing a rate case. However, in an effort to reduce the disputed issues in this proceeding, the Company will agree to make such a filing 30 days prior to its next natural gas or electric general rate cases.

c. Xcel Energy uses an accepted industry standard approach to developing econometric models, and includes the most current economic and demographic data available at the time of modeling. The Company does not believe any change in Xcel Energy's modeling process is necessary. The Company will continue to work with the Department on forecasting issues; however, this recommendation need not be affirmatively addressed in this proceeding.

d. Conceptually, the Company agrees with the Department that there is value in integrating the various models to avoid the potential for error. The Company is willing to commit to work with the Department on development of new tools for our revenue model and to determine if we can create the linkage sought without losing the flexibility of our other efforts in the areas of forecasting and the CCOSS. We do not believe that this should be a filing requirement as we are not certain today if we can satisfy the technical aspects of the proposal, nor would we know if we had met the request. Rather than modify the filing requirements for a single utility, we recommend that the Company commit to work with the Department on the development of a more integrated approach prior to our next general rate case filing. We anticipate the need to file rate cases more frequently than in the past and as such, we have a strong interest in achieving the same objectives sought by the Department of minimizing errors and providing sufficient clarity to allow for regulatory review.

278. The Department accepted the above statements as an adequate response to its requests.[356]

VI. MISCELLANEOUS

A. Financial Neutrality Factor

279. When Xcel invests in Conservation Improvement Programs (CIP) or Demand Side Management (DSM) it lowers its demand for electricity. Absent such CIP investments, Xcel would have to build a new electric plant to meet incremental demand. Such construction may be avoided by investing in CIP instead. When substituting CIP for building new electric plants, Xcel maintains it loses the theoretical incremental revenues and earnings that it would have theoretically received from operating the power plant, absent the CIP investments.[357]

280. Xcel seeks to be compensated for the loss of these theoretical revenues and earnings associated with CIP investment by requesting a return on the equity portion of its CIP investment. If, for example, Xcel avoided building and operating a plant for one megawatt (MW) as a result of investing in CIP, Xcel contends that it should receive an additional return on the equity that it would have theoretically invested in the plant to add that one MW of electric capacity. Xcel argues that its proposal will result in equal treatment of CIP investment and electric plant investment. Therefore, it has advanced a rider mechanism it calls the Financial Neutrality Factor (FNF).

281. The proposed FNF mechanism would encourage Xcel to implement the expanded demand-side management (DSM) goals that are pending in its 2004 Resource Plan proceeding.[358] In that proceeding, the Department has recommended a significant increase in Xcel's DSM goals.[359] The Department agrees that achievement of these expanded goals will require Xcel to pursue and develop new conservation methods using different and unfamiliar technologies.[360]

282. Xcel maintains that achievement of the pending DSM goals will require substantial effort on its part. Specifically, Xcel maintains that the Commission should recognize those goals as "stretch goals," particularly in relation to energy savings, achievement of which would benefit ratepayers. Xcel further maintains that current mechanisms are not sufficient for achieving financial neutrality among resource options.[361]

283. The proposed FNF would be based on the lost earnings opportunity associated with avoided capital investments that result from expanded DSM efforts recommended in the Resource Plan proceeding.[362] The FNF would be based on the costs of a base load power plant (which is anticipated as being needed during the resource planning period), the cost of equity and capital structure authorized in this rate case proceeding, and the achieved demand

savings filed in Xcel's Conservation Improvement Program (CIP) reports.[363] Specifically, the FNF would reward Xcel for achieving approximately 275 MW more demand savings than the demand-savings goals it assumes it would achieve if it were to spend $43 million per year for the years 2005-2019 (a 15-year goal of 878 MW).[364]

284. Most of the other parties objected to this proposal, including the Department, the OAG, ECC, the Commercial Group, and the Large Industrial Group. Among other things, these parties expressed concern that the proposal was not specifically authorized by Minnesota law, would unreasonably increase customer's bills, and would reward Xcel for actions it would have taken anyway.

285. With regard to the argument that such a mechanism would be legally impermissible, the Administrative Law Judge disagrees. Minnesota law provides broad authority to the Commission to establish just and reasonable rates and to set rates to the maximum reasonable extent to encourage energy conservation.[365] The Commission could approve a mechanism intended to provide an economic incentive for utilities to achieve DSM goals that would be entirely legal, as long as resulting rates were just and reasonable.

286. With regard to the argument that this specific proposal would result in unreasonable rates, the Department contends first that state law already gives preferential tracker treatment to recovery of CIP investment, along with an incentive mechanism that reasonably compensates Xcel. When Xcel invests in CIP it gets a timely dollar-for-dollar recovery of its CIP expenses in rates through its Resource Adjustment Factor. Recovery of actual CIP expenses continues between rate cases. Consequently, there is no under-recovery of CIP expenses. Timely recovery of CIP expenditures allows Xcel to use those funds for other investments.[366]

287. In addition, the Department maintains that the proposed FNF would not make Xcel indifferent as to conservation versus plant investment, because there is already a greater financial incentive to invest in CIP than in plant. When Xcel invests in CIP, it receives timely dollar-for-dollar recovery of its expenses. This means that investment in CIP lowers a utility's investment risk in comparison to investing in new plants. When the Company invests in new plant it gets no recovery until the plant is allowed in the rate base at the time of the next rate case.[367] Furthermore, power plant construction poses its own risks with respect to managing costs, and there is always a risk that the utility will not receive the level of recovery it seeks from ratepayers. Once the plant is in the rate base, there is no guarantee that Xcel will fully recover its investment. The utility risks under-recovery of its investment cost if it fails to reach its allowed rate of return.[368]

288. Finally, the Department argues that the FNF criteria would reward Xcel unreasonably for meeting demand-savings goals it will easily achieve. While Xcel's energy savings goal may be more difficult to achieve than demand

savings, the proposed FNF sets a low bar for Xcel based on meeting demand savings goals.[369] The demand-savings threshold under the proposed FNF is actually lower than what Xcel has been achieving.[370] For example, the FNF would allow Xcel to reap more than $90 million from ratepayers over the next five years merely by achieving the average MW demand savings it met between 1998 and 2004. An award of $24,712,500 would be granted in 2010 alone, and that amount would be on top of any Shared Savings DSM Financial Incentive.

289. The Administrative Law Judge agrees that the proposed FNF is unreasonably expensive for ratepayers and recommends that the Commission reject it.

290. Given the pending need for base load resources, growing environmental concerns, and volatile electricity and fuel prices, however, the challenges of meeting future resource needs will clearly be more significant than experienced in the past. There is some agreement among the objecting parties that mechanisms like the FNF could be structured to send appropriate economic signals to encourage aggressive efforts that would reduce the need for relatively expensive base load generation at this critical time.[371]

291. The Department contended that an energy-based incentive approach, as opposed to Xcel's capacity-based approach, could be appropriate, but it should not be addressed in this general rate case proceeding.[372] The Department offered to continue to work with Xcel to develop an appropriate mechanism in another forum.[373] This suggestion for an energy-based approach is consistent with the Department's recommendations in the Resource Plan proceeding.[374]

292. Xcel is willing to develop such a proposal but requests that it be done in a specific timeframe.[375]

B. Miscellaneous Issues Resolved Through Testimony

1. Street Lighting

293. The SRA did not object to Xcel's rates for streetlight service, but raised concerns about Xcel's response to street light outages in certain communities.[376]

294. To address these concerns, Xcel and SRA reached a resolution in which Xcel has committed to monthly meetings with affected communities to address street-light outage concerns.[377] This resolution will make sure the street-light repair concerns of the SRA are addressed on a regular basis as those concerns arise. The resolution is in the public interest.

2. Contract Renewable Service

295. The MCETF and the Chamber sponsored proposals that would provide customers with greater ability to select generation resources. The MCETF was interested in changes to the WindSource tariff that would allow a large volume rate and the ability to purchase wind energy generated by a third party using Xcel's distribution service.[378] The Chamber proposed allowing customer-owned or customer-controlled generation to be delivered across Xcel's facilities to a customer's distant load at the customer's cost, not at the WindSource rate.[379]

296. Xcel noted in its response that such proposals raised a number of challenging policy and legal questions related to retail wheeling and other issues and that such issues should not be explored in this rate proceeding.[380] Nevertheless, Xcel offered to work with the parties to discuss whether there is a way to address the concerns and goals of the Chamber and presumably the MCETF, either by designing changes to the WindSource tariff or through a generic proceeding in which all regulated electric utilities would participate.[381] Both the Chamber and MCETF appear to have accepted Xcel's commitment as a resolution of this issue.[382]

3. Customer Rights/Rules and Regulations

297. Xcel proposed adding a new tariff section addressing customer rights issues such as disconnection, cold weather disconnection, disputes, and payment arrangements similar to the section added in the Gas Tariff as part of its settlement in the 2004 Natural Gas Rate Case. The Department recommended several additions to the proposed new tariff.[383] Xcel has accepted all the Department's proposed additions.[384] As modified to reflect the Department's recommendations, no party opposes this new tariff language. No party opposes the processing charge or tariff as modified to reflect the Department's recommendations.

4. Cost Allocations

298. Xcel maintained that its accounting policies and procedures accurately assign and allocate costs among all relevant legal entities, utilities, jurisdictions and non-regulated business activities.[385] Its proposed allocations are consistent with allocation principles established by the Commission, and the Department has recommended no adjustments to these allocations.[386] No other party has expressed any objections. This matter is accordingly uncontested.

5. Purchase Capacity Equity Rider

299. In its Direct Testimony, Xcel proposed a mechanism referred to as a Purchase Capacity Equity Rider to address concerns related to imputed debt associated with capacity purchases. In response to concerns raised by many parties and to narrow the number of issues in dispute, Xcel withdrew its proposal.[387]

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. Chapters 216B and 14.50.

2. Every rate made, demanded, or received by any public utility shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05. Any doubt as to reasonableness should be resolved in favor of the consumer.[388]

3. The burden of proof to show that a rate change is just and reasonable shall be upon the public utility seeking the change.[389]

4. If an applicant and all intervening parties agree to a stipulated settlement of the case or parts of the case, the settlement must be submitted to the Commission. The Commission shall accept or reject the settlement in its entirety. The Commission may accept the settlement on finding that to do so is in the public interest and is supported by substantial evidence.[390]

5. In the event that the Commission rejects the agreements of the parties, this matter may be extended by 60 days for conclusion of the contested case proceedings under the terms of Minn. Stat. § 216B.16, subds. 1a and 2.

6. The record supports the resolution of the settled, resolved, and uncontested matters identified above. These matters have been resolved in the public interest and are supported by substantial evidence.

7. Rates set in accordance with the terms of this Report would be just and reasonable.[391] Specifically, the record supports resolution of the contested issues in the following manner:

   a. Rates should be adjusted by increasing net revenues in the amount of $16,637,966, effective January 1, 2007, to reflect the return of Flint Hills as a full-requirements customer;

   b. The appropriate level of post-retirement medical benefits to include in rates is $8,967,000;

c. Xcel has established that tree trimming expenses should be increased by $2 million;

d. Incentive compensation in the amount of $5,135,634 should be allowed in rates;

e. A 6-year amortization period should be used for recovering the investment in a private independent spent fuel storage installation;

f. Xcel should be allowed to recover all of its deferred expenses related to the Time-of-Use pilot program;

g. The appropriate return on equity is 10.64%;

h. The appropriate rate of return is 8.86%;

i. Rates should include Xcel's test year income tax expense;

j. Xcel's embedded Class Cost of Service Study is reasonable;

k. The revenue requirement should be allocated to customer classes in the manner proposed by the Department;

l. The FCR mechanism should be adjusted to incorporate the E8760 allocator, but the two-step method of adjusting rates should be retained;

m. Xcel's Dual Feeder Service rates are reasonable;

n. Xcel's proposed interruptible riders are reasonable;

o. The fuel clause credit for the WindSource rate should be based on average, not marginal, cost;

p. The amount of contribution in aid of construction (CIAC) should be determined based on the 3.5 times revenue formula proposed by Xcel;

q. Xcel should be allowed to determine the form of payment for CIACs; and

r. The Financial Neutrality Factor proposed by Xcel is not reasonable and should be rejected.

Based upon these Conclusions, the Administrative Law Judge makes the following:

RECOMMENDATION

The Administrative Law Judge recommends that the Commission issue an Order providing that:

1. Xcel is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. Within ten days of the service date of this Report, Xcel shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirements for 2006 and 2007 and the rate design decisions based on the recommendations contained herein.

3. If the Commission orders an Interim Rate Refund within 30 days of the service date of this Order, Xcel shall file with the Commission for its review and approval, and serve upon all parties to this proceeding, a proposed plan for refunding to all customers, with interest, the revenue collected during the Interim Rate period in excess of the amount authorized herein.

4. Xcel shall make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: July 6, 2006

s/Kathleen D. Sheehy

KATHLEEN D. SHEEHY
Administrative Law Judge

Reported: Transcript prepared (nine volumes)
Shaddix & Associates

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, any party adversely affected by this Report may file exceptions to it within 15 days of the mailing date hereof. Exceptions should be filed with the Executive Secretary, Minnesota Public Utilities Commission, 350 Metro Square, 121 Seventh Place East, St. Paul, MN 55101. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties. If desired, a reply to exceptions may be filed and served within ten days after the service of the exceptions to which reply is made. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply. An original and 15 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions or after oral argument, if held. Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that the recommendation has no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 216B.16, subd. 1a, if the Commission rejects or modifies the settlement agreements reached herein, this matter may be extended by 60 days for conclusion of the proceeding.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.

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[1] The Commercial Group consists of the Minnesota locations of Lowe's Home Centers, Inc.; Wal-Mart Stores East, LP; Big Lots Stores, Inc.; Best Buy Co., Inc.; Federated Department Stores, Inc.; and Kohl's Department Stores, Inc.

[2] *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-05-1428, Order Accepting Rate Case Filing and Suspending Rates (December 30, 2005); Order Referring the Case to the Office of Administrative Hearings for Contested Case Proceedings (December 30, 2005).

[3] *Id*., Order Setting Interim Rates (December 30, 2005).

[4] First Prehearing Order, January 20, 2006.

[5] Second Prehearing Order, February 24, 2006; letter dated February 24, 2006, from Rebecca Winegarden to the ALJ and Commission.

[6] The Administrative Law Judge received 46 written comments; about 25 of them were from members of the Legislative Advocacy Project at St. Stephens Catholic Church in Minneapolis.

[7] Ex. 4, Robinson Direct at 37.

[8] Ex. 107, Lusti Direct at 6 (DVL-11).

[9] Ex. 5, Robinson Rebuttal at 32.

[10] Ex. 22, Poferl Rebuttal at 14, 17, 24.

[11] Tr. 9:37.

[12] *In the Matter of the Petition of Northern States Power Company for Approval of an Electric Supply and Power Purchase Option Agreement Between NSP and Koch Refining Company, L.P.*, Docket No. E-002/M-96-1123, Order Approving Agreement (February 4, 1997); Ex. 93, Direct Ex. 7 of Ham, (HKH-7) Schedule 4.

[13] Ex. 22, Poferl Rebuttal at 19.

[14] Ex. 91, Ham Direct at 14-15.

[15] Ex. 22, Poferl Rebuttal at 28; Tr. 5:51; Ex. 95, Ham Surrebuttal at 3.

[16] Ex. 47, Attachment A to Information Request DOC-19; Ex. 95, Ham Surrebuttal at 3-6; Ex. 110, Lusti Surrebuttal at 8-16.
[17] Ex. 47, Attachment A to Information Request DOC-19. This Attachment contains some trade secret information. During the hearing, the exhibit was revised so that the net margin increases calculated by the parties ($19,524,997 by the Department; $17,507,920 by the Company for the A14 rate, and $16,637,966 for the A15 rate) were not trade secret information.
[18] Ex. 47, Attachment A to Information Request DOC-19.
[19] Tr. 9:52-53.
[20] Tr. 9:52; Ex. 1, vol. 4, § V Operating and Maintenance, Tab A-17, page A-17-B.
[21] Ex. 94, Ham Surrebuttal at Schedule 10 (Load obligation line).
[22] Ex. 8, Marks Direct at 3.
[23] Tr. 9:46.
[24] Initially, the Department did dispute the accuracy of these jurisdictional amounts, but it accepted these figures during the course of the hearing. *See* Tr. 8:93.
[25] Ex. 28, Erickson Rebuttal at 2.
[26] Ex. 28, Erickson Rebuttal at 2-3.
[27] Ex. 103, Campbell Direct at 63.
[28] The pool of beneficiaries has been closed since 1999. *See* Ex. 27, Erickson Direct at 7.
[29] Ex. 106, Campbell Surrebuttal at 30.
[30] Ex. 41.
[31] *In the Matter of the Petition by Interstate Power Company to Increase Electric Rates*, Docket No. E-001/GR-03-767, Findings of Fact, Conclusions of Law, and Order, Order Modifying Settlement at 24 (April 5, 2004).
[32] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Natural Gas Service in the State of Minnesota*, Docket No. G-002/GR-04-1511, Order Accepting and Modifying Settlement and Requiring Compliance Filings (Aug. 11, 2005).
[33] Ex. 114 at 7.
[34] Ex. 4, Robinson Direct at 53-56.
[35] Ex. 5, Robinson Rebuttal at 19-21.
[36] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Annual Safety, Reliability and Service Quality Report Under Minnesota Rules Chapter 7826,* Docket No. E-002/M-05-551, Order Accepting Annual Reports, Setting Reliability Standards, and Setting Filing Requirements at 5 (April 7, 2006) (*Service Quality Order*).
[37] *Id*.
[38] Tr. 8:100.
[39] Ex. 106, Campbell Surrebuttal at 25-26.
[40] *Id*. at 7-15.
[41] *In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates of Electric Service in the State of Minnesota,* Docket No. E002/GR-92-1185, Order After Reconsideration at 7-8 (Jan. 14, 1994).
[42] *Id*. at 6.
[43] *Id*. at 7.
[44] Ex. 24, Sanford Direct at 21; Ex. 43; Ex. 110, Lusti Surrebuttal at DVL S-14.
[45] Ex. 112.
[46] Ex. 24, Sanford Direct at 21.
[47] Ex. 24, Sanford Direct at 2, 23.
[48] *Id*. at 2.
[49] Ex. 108, Lusti Direct at 9. As noted above, no target levels were set for 2003; Xcel has used a budgeted number as a proxy for the target. Information for 2005 is incomplete.
[50] In Xcel's recent natural gas rate case, incentive compensation was set with a 25 percent cap.
[51] Ex. 24, Sanford Direct at 16.
[52] Ex. 43.
[53] $9,354,666 plus $689,266 = $10,042,932
[54] Ex. 112. This percentage includes all available data for 2005, which is not final. If 2005 were excluded, the average payout percentage would be higher (66%).

[55] $10,042,932 x 58% = $5,824,900.
[56] *See* Ex. 1, vol. 4, Tab IX Interim at 8 (target IP award over 25% is $858,348, times jurisdictional shares is $689,266).
[57] If these numbers are computed incorrectly, the parties should correct them as necessary. Xcel also calculated that the amount that would be excluded to reflect a cap of 15% of base salary is $1,242,037. *See* Ex. 1, vol. 4, Tab IX Interim at 8 (target IP award over 15% is $1,546,746, times jurisdictional shares is $1,242,932). If the Commission were to use this method but impose a 15% cap on base salary, the resulting test year expense would be $4,582,863.
[58] Ex. 23, Bomberger Direct at 19-21.
[59] *Id*. at 21.
[60] *Id*.
[61] Ex. 23, Bomberger Direct at 21-22.
[62] Ex. 103, Campbell Direct at 60; Ex. 5, Robinson Rebuttal at 22. This amount reflects an adjustment made by Department, which Xcel accepted.
[63] Tr. 1:150-52.
[64] Ex. 106, Campbell Surrebuttal at 27.
[65] Ex. 103, Campbell Direct at 61.
[66] Tr. 8:101-02.
[67] Ex. 5, Robinson Rebuttal at 23.
[68] Tr. 8:102.
[69] The difference between Xcel's and the Department's proposals is less than 0.05% of Xcel's total operating revenues. Use of the Department's 10-year amortization period would result in a test year expense of about $1,731,567 ($23 million divided by ten years times jurisdictional shares). *See* Department's Initial Brief at 47. Use of Xcel's 6-year amortization period would result in a test year expense of about $2,885,944 ($23 million divided by six years times jurisdictional shares).
[70] *In the Matter of an Investigation Into Using Rate Design to Achieve the Demand-Side Management Goals of Xcel Energy*, Docket No. E-002/CI-01-1024, Order Modifying Procedural Schedule and Making Other Changes (April 24, 2002).
[71] *In the Matter of an Investigation into Using Rate Design to Achieve the Demand Side Management Goals of Xcel Energy*, Docket No. E002/CI-01-1024, Order Declining to Proceed with Pilot Project at 4 (June 23, 2003).
[72] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of Deferred Accounting for Costs Incurred for the Web Tool and Time-of-Use Pilot Project*, Docket No. E002/M-03-1462, Order Approving Deferred Accounting at 5 (February 25, 2005) (*TOU Order*).
[73] *Id*.
[74] Ex. 4, Robinson Direct at 62.
[75] Ex. 70, Nelson Direct at 31-32.
[76] *TOU Order* at 5.
[77] Ex. 45, Settlement Agreement – Wholesale Margins at 1.
[78] *Id*.
[79] Id. at 2; Tr. 4:37.
[80] Ex. 45 at 2-3; Tr. 4:38.
[81] Ex. 103, Campbell Direct at 39, 43; Ex. 106, Campbell Surrebuttal at 18-19.
[82] Ex. 45, Settlement Agreement – Asset and Non-Asset Based Margins at 3-4; Tr. 4:38-39.
[83] Ex. 104, Campbell Direct at 48; Ex. 20, Imbler Rebuttal at 19.
[84] Ex. 5, Robinson Rebuttal at 26. Xcel did not propose a method for recovering the other 30 MISO Day 2 charge types, as these issues are being considered in Docket No. E002/M-04-1970 (hereinafter, the MISO Docket).
[85] *Id*.
[86] *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-05-1428, Order Setting Interim Rates at 7 (December 30, 2005).
[87] Tr. 4:44-45; Tr. 6:72.

[88] *Id*.
[89] *Id*.
[90] Ex. 51, Schedin Direct at 9-11.
[91] Ex. 16, Beuning Rebuttal at 8-21; Ex. 20, Imbler Rebuttal at 23.
[92] Ex. 46, Settlement Agreement – FCA at 1-2; Tr. 4:40-41.
[93] Customers would need to sign an appropriate protective agreement to obtain access to this information.
[94] Ex. 106, Campbell Surrebuttal at 2-3; Ex. 5, Robinson Rebuttal at 8-10.
[95] Ex. 5, Robinson Rebuttal at 10.
[96] Ex. 5, Robinson Rebuttal at 18.
[97] Ex. 103, Campbell Direct at 53-54; Ex. 107, Lusti Direct at 19.
[98] Ex. 5, Robinson Rebuttal at 18.
[99] Docket No. E,G002/PA-99-1031, Order Approving Merger, as Conditioned, at 10 (June 12, 2000).
[100] Ex. 21, Poferl Direct at 8-9.
[101] Ex. 4, Robinson Direct at 64-65.
[102] Ex. 85, Davis Direct at 19-20.
[103] Ex. 4, Robinson Direct at 66.
[104] Ex. 85, Davis Direct at 21.
[105] Ex. 85, Davis Direct at 21-22.
[106] Ex. 5, Robinson Rebuttal at 33.
[107] Ex. 80, Ouanes Direct at 80.
[108] Tr. 7:80-81.
[109] Ex. 5, Robinson Rebuttal at 29-30.
[110] *Id*.
[111] Ex. 106, Campbell Surrebuttal at 33-36.
[112] Tr. 6:60-62; Tr. 8:89-91; s*ee generally* Ex. 49, Huso Direct.
[113] Tr. 8:109.
[114] Ex. 4, Robinson Direct at 47; Ex. 5, Robinson Rebuttal at 34.
[115] Tr. 1: 94.
[116] Tr. 9:8.
[117] Ex. 4, Robinson Direct at 10.
[118] Ex. 88, Ham Direct at 3.
[119] Ex. 5, Robinson Rebuttal at 26.
[120] *Id*.; Ex. 103, Campbell Direct at 18.
[121] Ex. 5, Robinson Rebuttal at 26.
[122] Ex. 107, Lusti Direct at 14.
[123] Ex. 5, Robinson Rebuttal at 7.
[124] *Id*.
[125] Ex. 109, Lusti Surrebuttal at 8.
[126] Xcel Reply Brief at 29-30.
[127] Ex. 7, Petree-Schmidt Direct.
[128] Ex. 103, Campbell Direct at 10.
[129] Ex. 10, Tyson Direct at 3.
[130] Ex. 76, Amit Direct at 2, 7.
[131] Ex. 10, Tyson Direct at 17.
[132] Ex. 10, (GET-1), Schedule 2.
[133] Ex. 10, Tyson Direct at 23.
[134] Ex. 76, Amit Direct at 32-33.
[135] *Id*.
[136] Ex. 32, Reed Direct at 3.
[137] *Id*.
[138] *Id*.
[139] *Id*. at 5-11.
[140] *Id*. at 10.
[141] *Id*.

[142] Ex. 32, Reed Direct at 13-14, 18.
[143] *Id*. at 16.
[144] *Id*.
[145] *Id*. at 20-21; Ex. 33A (JJR-3) Schedule 1.
[146] Ex. 32, Reed Direct at 20.
[147] *Id*. at 23.
[148] *Id*.; *id*. at (JJR-1), Schedule 8.
[149] Ex. 33, Reed Rebuttal at 4.
[150] Ex. 32, Reed Direct at 5.
[151] *Id*. at 14-15; Ex. 33, Reed Rebuttal at 3.
[152] Ex. 32, Reed Direct at 14-15; Ex. 33, Reed Rebuttal at 3.
[153] Ex. 76, Amit Direct at 35-36; Ex. 75, Amit Direct at 15.
[154] Ex. 51, Sass Direct at 4, 31 and 32.
[155] Ex. 96, Selecky Direct (OAG) at 8.
[156] Tr. 8:39.
[157] *Id*.
[158] Tr. 8:67.
[159] Ex. 32, Reed Direct at 15; Ex. 33, Reed Rebuttal at 3.
[160] Ex. 32, Reed Direct at 10-11.
[161] Ex. 97, Selecky Surrebuttal at 4.
[162] Tr. 8:52.
[163] Tr. 8: 52 – 53.
[164] Ex. 32, Reed Direct at 20 (S&P Index includes debt with *average* maturity of 15 years) (emphasis added).
[165] Ex. 12, Hevert Direct at 22.
[166] *Id*. at 20.
[167] *Id*. at 15-18.
[168] *Id*. at 23-25.
[169] *Id*. at 30-32
[170] *Id*. at 41.
[171] Ex. 73 Amit Direct at 23-24.
[172] *Id*. at 29-30.
[173] *Id*. at 14-15.
[174] *Id*. at 2, 30.
[175] OAG Initial Brief at 36.
[176] *See generally* Ex. 73, Amit Direct at 2-12.
[177] Ex. 13, Hevert Rebuttal at 6-7.
[178] *Id*. at 8-9.
[179] *Id*. at 9-10.
[180] *Id*. at 10.
[181] *Id*.
[182] Ex. 13, Hevert Rebuttal at 11.
[183] Ex. 76, Amit Surrebuttal at 2.
[184] *Id*. at 6.
[185] *Id*.
[186] *Id*.
[187] *Id*. at 20.
[188] Ex. 73, 74, Amit Direct at 44.
[189] Ex. 75, Amit Direct at 16-18; Ex. 13, Hevert Rebuttal at 26-27; Ex. 12, Hevert Direct at 15-16.
[190] Ex. 97, Selecky Surrebuttal (OAG) at 9. Myer Shark did not sponsor this testimony, but he supports this recommendation.
[191] Ex. 6, Robinson Rebuttal at 42.
[192] Tr. 1:139-43.
[193] *See In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Docket No. GE-999/CI-90-1008, Order Setting Filing Requirements (September 28, 1994).

[194] Tr. 1:97, 153.
[195] Ex. 31, Duevel Rebuttal at 5-6.
[196] *Id*. at 5 and (JJD-2), Schedule 2.
[197] Ex. 5, Robinson Rebuttal at 42-43.
[198] Tr. 2:35, 39, 92, 95.
[199] Tr. 2:35, 49, 88, 94.
[200] Tr. 2:34-35.
[201] Ex. 31, Duevel Rebuttal at (JJD-2), Schedule 1.
[202] Ex. 31, Duevel Rebuttal at (JJD-2), Schedule 2.
[203] Ex. 31, Duevel Rebuttal at 7.
[204] Tr. 2:95.
[205] Ex. 31, Duevel Rebuttal at 8.
[206] *Id*.
[207] *Id*. at 12.
[208] *Id*. at 9.
[209] *Id*.
[210] *Id*. at 9-10.
[211] *Id*. at (JJD-2), Schedule 3.
[212] Ex. 31, Duevel Rebuttal at 11.
[213] *Id*.
[214] Ex. 29, Duevel Direct at 12; Tr. 2:93.
[215] Ex. 3, Sparby Rebuttal at 12, 46.
[216] *See, e.g. Request by Northern States Power Company for Statement to the Securities and Exchange Commission Regarding Investments in Foreign Utility Companies*, Docket No. E002/S-97-1652, Order Approving at 1-2 (March 10, 1998).
[217] Ex. 3, Sparby Rebuttal at 12-13.
[218] *In the Matter of an Inquiry into Possible Effects of Financial Difficulties at NRG and Xcel Energy on NSP and its Customers*, Docket No. E002/CI-02-1346 (*Financial Inquiry Docket*).
[219] *Financial Inquiry Docket*, Order Requiring Additional Information and Audit at 7-10 (October 22, 2002) (*Financial Inquiry Order*).
[220] Ex. 3, Sparby Rebuttal at 13.
[221] Ex. 75, Amit Direct at 11-17.
[222] Tr. 1:106-07; Ex. 6, Robinson Rebuttal at 47-50.
[223] Ex. 4, Robinson Direct at 72.
[224] Ex. 6, Robinson Rebuttal at 47-48.
[225] Ex. 96, Selecky Direct (OAG) at 11-12.
[226] Ex. 4, Robinson Direct at 72-73.
[227] *Id*.; Ex. 6, Robinson Rebuttal at 47-48.
[228] Ex. 6, Robinson Rebuttal at 49.
[229] Ex. 29, Duevel Direct at 15.
[230] Tr. 8:44-45.
[231] Ex. 96, Selecky Direct (OAG) at 5-7.
[232] Ex. 6, Robinson Rebuttal at 44-45; Tr. 1:103, 3:17.
[233] Ex. 12, Tyson Rebuttal at 6; Tr. 3:18.
[234] Ex. 12, Tyson Rebuttal at 9.
[235] *Id*. at 6-7.
[236] Ex. 5A, Revision of (JJR-2), Schedule 13.
[237] Ex. 12 Tyson Rebuttal at 6; Tr. 1:110, 112; Tr. 3:18.
[238] Ex. 13, Hevert Rebuttal at 31.
[239] *Id*.
[240] Ex. 80, Ouanes Direct at 15-17.
[241] Ex. 37, Zins Direct at (PJZ-1) Schedule 2; Ex. 1, vol. 3.
[242] Docket No. E002/GR-92-1185.
[243] Ex 37, Zins Direct at 5.
[244] Ex. 37, Zins Direct at 13.
[245] Ex. 80, Ouanes Direct at 22; Ex. 83, Ouanes Surrebuttal at 2.

[246] Ex. 57, Higgins Direct at 14-15.
[247] Ex. 37, Zins Direct at 8.
[248] *Id*.
[249] Ex.80 Ouanes Direct at 19.
[250] Ex., Nelson at 27; Ex. 59, Duffrin Direct at 19-20.
[251] Ex. 38, Zins Rebuttal at 12. A discussion of the E8760 alloctor's use with respect to fuel costs is provided in a separate section of this Report.
[252] Ex. 113, Selecky Direct (Large Industrial Group) at 15-16.
[253] Tr. 8:74-75.
[254] Ex. 54, Schedin Rebuttal at 22-23.
[255] Tr. 8:78.
[256] Ex. 54, Schedin Rebuttal at 23.
[257] Tr. 8:75-77.
[258] Ex. 82, Ouanes Rebuttal at 7.
[259] Ex. 38, Zins Rebuttal at 5-6.
[260] *In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates of Electric Service in the State of Minnesota*, Docket No. E002/GR-92-1185,Findings of Fact, Conclusions of Law, and Order at 115 (September 29, 1993); Ex. 1, vol. 3.
[261] Ex. 37, Zins Direct at 14.
[262] Ex. 80, Ouanes Direct at 30-31.
[263] Ex. 37, Zins Direct at 17; Ex. 79, Peirce Surrebuttal at Schedule 11.
[264] *Id*.; Ex. 57, Higgins Direct at 17.
[265] Ex. 77, Peirce Direct at SLP-2.
[266] Ex. 113, Selecky Direct (Large Industrial Group) at 19.
[267] Ex. 58, Higgins Rebuttal at 2.
[268] Ex. 52, Schedin Direct at 21-23.
[269] Ex. 70, Nelson Direct at 11.
[270] Ex. 37, Zins Direct at 17-18.
[271] Ex. 39, Zins Rebuttal at 7-9; Tr. 7:59-60.
[272] Ex. 77, Peirce Direct at SLP-2; Tr. 7:64-67.
[273] Ex. 80, Ouanes Direct at 4.
[274] Xcel's Initial Brief at 155-56.
[275] *In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy to Separate the Fule Clause Adjustment from the Resource Adjustment*, Docket No. E002/M-02-2097, Order Accepting Proposal as Modified at 4 (Jan. 4, 2005).
[276] Tr. 7:83-84.
[277] Docket No. E999/CI-03-802.
[278] Tr. 7:89-90; Tr. 3:62-63; Ex. 83, Ouanes Surrebuttal at 3.
[279] Ex. 80, Ouanes Direct at 26-28; Ex. 84, Ouanes Surrebuttal at 8-9. Without the FCR change, the WindSource premium would be $1.47 per 100 kWh.
[280] Ex. 38, Zins Rebuttal at 21-22.
[281] Ex. 52, Schedin Direct at 10.
[282] *Id*. at 92.
[283] *Id*.
[284] Xcel's Initial Brief, Ex. PJZ-2, Schedule 1, page 2 of 6; Department's Initial Brief at 75.
[285] Ex. 37, Zins Direct at (PJZ-1) Schedule 7. For example, Xcel no longer proposes to change the E8760 allocator annually and has agreed not to change it between rate cases. A virtual exemption from the rule would be required if Xcel is still proposing to move all fuel costs into the FCA.
[286] Tr. 3:22-23.
[287] Ex. 39, Zins Rebuttal at 29-30.
[288] *Id*. at 30.
[289] Department Initial Brief at 65.
[290] *In the Matter of a Petition by Northern States Power Company d/b/a Xcel Energy to Modify the Special Facilities Provisions of the Standard Installation and Extension Rules*, Docket No. E002/M-05-113, Order Rejecting Petition at 3 (July 27, 2005).

[291] Chamber Initial Brief at 14.
[292] Ex. 113, Selecky Direct (Large Industrial Group) at 33-34.
[293] Ex. 38, Zins Rebuttal at 34-35.
[294] Department Initial Brief at 67-68.
[295] *Id*.; *id*. at 71.
[296] Ex. 38, Zins Rebuttal at 28.
[297] *Id*. at 72.
[298] Department Initial Brief at 70.
[299] Ex. 77, Peirce Direct at 37.
[300] Ex. 38, Zins Rebuttal at 30.
[301] Ex. 34, Lehman Direct at 6.
[302] Ex. 77, Peirce Direct at 23-26.
[303] Ex. 113, Selecky Direct (Large Industrial Group) at 30-33.
[304] Ex. 35, Lehman Rebuttal at 17.
[305] Tr. 4:16; Tr. 8:70.
[306] Tr. 8:111.
[307] Ex. 36, Lehman Surrebuttal at 3.
[308] *Id*.
[309] Tr. 4:72-73.
[310] *See* Ex 113, Selecky Direct (Large Industrial Group) at 26.
[311] Ex. 36, Lehman Surrebuttal at 3.
[312] Ex. 52, Schedin Direct at 19-20.
[313] Ex.38, Zins Rebuttal at 37.
[314] Ex. 37A, Zines Direct at 44 (emphasis in original).
[315] *Id*.
[316] Ex. 37, Zins Direct at 45.
[317] Tr. 3:33.
[318] Ex. 38, Zins Rebuttal at 43.
[319] *Id*. at 43, (PJZ-2) Schedule 4.
[320] Tr. 3:36; Tr. 6:86.
[321] Ex. 52, Schedin Direct; Ex. 54, Schedin Surrebuttal at 13.
[322] Ex. 38, Zins Rebuttal at 44.
[323] Ex. 47, Settlement Agreement – Residential Customer Charge; Tr. 4:42-43.
[324] *Id*.
[325] *Id*.
[326] Tr. 4:43-44.
[327] Ex. 47, Settlement Agreement – Residential Customer Charge; Tr. 4:42-43.
[328] *Id*.
[329] Ex. 70, Nelson Direct at 3.
[330] Ex. 77, Peirce Direct at 10.
[331] *Id*.
[332] Ex. 83, Ouanes Surrebuttal at 12.
[333] Ex. 35, Lehman Rebuttal at 29.
[334] *Id*.
[335] Tr. 4:28-29.
[336] Ex. 35, Lehman Rebuttal at 13.
[337] *Id*.
[338] Ex. 79, Peirce Surrebuttal at 6; Ex. 69, Wagner Surrebuttal at 1; Ex. 66, Dietz Surrebuttal at 4 (agreeing that the Department's proposal, which Xcel adopted, is reasonable).
[339] Ex. 52, Schedin Direct at 21-23.
[340] Tr. 4:8-9.
[341] Tr. 6:74.
[342] Ex. 35, Lehman Rebuttal at 15; Ex. 68, Wagner Direct at 7; Ex. 67, Jacobson Direct at 7-8.
[343] Ex. 52, Schedin Direct at 20-21.
[344] Ex. 35, Lehman Rebuttal at 16.
[345] Ex. 37, Zins Direct at 30-31.

[346] *Id*.
[347] *Id*.
[348] Ex. 37, Zins Direct at 32-33.
[349] Ex. 85, Davis Direct at 2-4.
[350] *Id*. at 39-42.
[351] Ex. 79, Peirce Surrebuttal at 18-19.
[352] *Id*. at 38; Ex. 37, Zins Direct at 56-57.
[353] Tr. 3:80-81; Ex. 38, Zins Rebuttal at 44-45.
[354] Ex. 88 Ham Direct at 15-16.
[355] Ex. 9, Marks Rebuttal at 8; Ex. 38, Zins Rebuttal at 45-46.
[356] Tr. 7:110-113.
[357] Ex. 74, Amit Direct at 18-19.
[358] Docket No. E002/RP-04-1752 (Resource Plan proceeding).
[359] Ex. 87, DOC Resource Plan Comments at 19 (containing a discussion of the Department's support of "Goal+25%"). The Department's comments in the Resource Plan Proceeding indicate that achieving Goal+25 percent has the potential to eliminate a base load plant under no-externality and low-externality scenarios, or to eliminate intermediate and peaking (gas) plants under a high-externalities scenario.
[360] Ex. 87, DOC Resource Plan Comments at 18; Tr. 7:100; Tr. 4:95.
[361] Ex. 21, Poferl Direct at 46.
[362] *Id*. at 47, 53
[363] *Id*. at 47-48.
[364] Ex. 85, Davis Direct at 4-5.
[365] Minn. Stat. §§ 216B.01; 216B.16, subd. 6; 216B.03; 216B.241.
[366] Ex. 74, Amit Direct at 21-22; Ex. 76, Amit Surrebuttal at 22-23; Tr. 7:36.
[367] Ex. 74, Amit Direct at 22-23; Ex. 76, Amit Surrebuttal at 22-25.
[368] Tr. 7:36.
[369] Ex. 85, Davis Direct at 17.
[370] Tr. 7:97.
[371] See Tr. 7:130.
[372] Ex. 85, Davis Direct at 18; Tr. 7:103-04.
[373] Ex. 86, Davis Surrebuttal at 3.
[374] *See* Ex. 87 at 18.
[375] Ex. 22, Poferl Rebuttal at 12.
[376] *See generally* Ex. 63, Clancy Direct.
[377] Tr. 4:7.
[378] Ex. 115, Egan/Stafford Direct at 16.
[379] Ex. 52, Schedin Direct at 17.
[380] Ex. 35, Lehman Rebuttal at 20-21; Ex. 3, Sparby Rebuttal at 7-8.
[381] Ex. 3, Sparby Rebuttal at 7-8; Tr. 1:23.
[382] Tr. 6:75.
[383] Ex. 77, Peirce Direct at 47-48.
[384] Ex. 38, Zins Rebuttal at 45; Ex. 79, Peirce Surrebuttal at 3.
[385] *See generally* Ex. 7, Petree-Schmidt Direct.
[386] Ex. 103, Campbell Direct at 10.
[387] Ex. 11, Tyson Rebuttal at 12.
[388] Minn. Stat. § 216B.03.
[389] Minn. Stat. § 216B.16, subd. 4.
[390] Minn. Stat. § 216B.16, subd. 1a(b).
[391] The Administrative Law Judge has roughly estimated that the gross revenue deficiency for the period ending December 31, 2006, will be in the area of $143 million; and for January 1, 2007, forward will be in the area of $119 million. These estimates could well be incorrect. Xcel and the Department should perform their own calculations after receipt of this Report.